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Examining Committee **University of Alberta**

A Study of the Rheology, Stability and Pore Blocking Ability of Aqueous
Colloidal Gas Aphron Drilling Fluids

by

Nancy Ann Bjorndalen

A thesis submitted to the Faculty of Graduate Studies and Research
in partial fulfillment of the requirements for the degree of

Doctor of Philosophy

in

Petroleum Engineering

Civil and Environmental Engineering

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A Study in the Philosophy, History and Theory of Science
The Case of Quantum Mechanics

by

Henry John Durrant

A thesis submitted to the Faculty of Graduate Studies and Research
in partial fulfillment of the requirements for the degree of
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Faculty of Graduate Studies and Research

in

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Edmonton, Alberta

1999

This thesis is a study in the philosophy, history and theory of science. It is a study in the philosophy of science, in the history of science, and in the theory of science. It is a study in the philosophy of science, in the history of science, and in the theory of science. It is a study in the philosophy of science, in the history of science, and in the theory of science.

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ABSTRACT

Colloidal gas aphron (CGA) based drilling fluids are designed to minimize formation damage by blocking the pores of the rock with microbubbles, which can later be removed easily when the well is open for production.

Sizing CGA in accordance with the rock pore size distribution is essential for effective sealing of the pores during drilling. The effect of time, temperature, and pressure on the stability and size of the CGA needs to be better understood in order to design a fluid that will sufficiently block the pores of the formation for extended periods. The physical properties of the CGA based drilling fluids need to be known for more effective drilling. Most importantly, the mechanism behind the blocking ability is not fully understood for the CGA drilling fluid.

The physical properties of CGA based drilling fluids are investigated. The results of rheology, API filtration loss and density measurement tests using various CGA based drilling fluid formulations are presented. The effects of time, pressure and temperature on the size and the stability of CGA based drilling fluids are investigated.

The pore blocking ability of the CGA fluid is investigated visually through micromodel experiments. Pore blocking is investigated further with sandpack experiments. The effect of CGA fluid composition, flow rates, type of reservoir saturating fluids, permeability and wettability on the resistance to CGA drilling

fluid flow through porous media (i.e., pressure drop due to CGA fluid flow) is investigated. An increasing resistance to flow of CGA drilling fluids through porous media is observed as more CGA fluid is injected.

Finally, results for the prediction of the CGA diameter through the investigation of two models, the drainage model and the bubble break-up model, are presented. A new prediction method for determining CGA diameter with pressure and temperature is developed. As well, a PVT cell was used to find the effect of pressure and temperature on the bulk fluid and an equation of state is developed to predict bulk density. This prediction method can be used in the field for a specific reservoir.

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NOMENCLATURE

A	=	Cross-sectional area of the core (ft^2)
C_1	=	Constant
C_2	=	Constant
C_3	=	Constant
CGA	=	Colloidal Gas Aphron
CMC	=	Critical Micellar Concentration
d	=	Pore diameter
d	=	diameter of the CGAs
D	=	Impeller diameter
d_{32}	=	Sauter mean bubble diameter
DDBS	=	Sodium Dodecyl Benzene Sulfonate
d_g	=	Sand grain diameter .
d_{max}	=	maximum bubble diameter
E	=	energy dissipation rate per unit mass (bubble break up model)
g	=	gravitational coefficient
h_i	=	height of the drained surfactant solution.
h_{lo}	=	initial solution height
h_t	=	total height of the solution
HTAB	=	Hexdecyltrimethyl ammonium bromide
HU	=	Hounsfield Unit
k	=	permeability (Darcy)
L	=	length of the scale of primary eddies
L	=	length of the core (ft).
N_i	=	mixing speed
P	=	Power consumption
p_1	=	Pressure exerted by the gas bubble,
p_2	=	Pressure exerted by the gas bubble
p_3	=	Pressure exerted by the liquid
ΔP	=	Resistance of fluid displacement

ΔP	=	Change in pressure along the core length (psi) (Darcy's Law)
P_c	=	Capillary pressure
PV	=	Pore Volume
q	=	Flow rate (bbl/day)
r	=	Radius of the tube
r_1	=	Capillary radius
r_2	=	Original radius of the CGA.
Re	=	Impeller Reynolds Number
r_H	=	hydraulic radius
$\overline{u^2}$	=	mean square velocity difference over d_{max}
V	=	liquid volume
V_i	=	Impeller swept volume
W	=	blade width.
W_{e_c}	=	Critical weber number
XG	=	Xanthan Gum
γ	=	Interfacial tension
ϵ	=	gas holdup of the aphronic phase (drainage model)
η	=	length of scale of the energy dissipating eddies of the viscous subrange
θ	=	contact angles of gas bubbles 1
θ'	=	contact angles of gas bubbles 2
μ	=	viscosity of the liquid phase (cp).
μ_w	=	viscosity of the water
ρ	=	density of the liquid phase
ρ_w	=	density of the water
ρ_a	=	density of the CGA.
σ	=	surface tension
ν	=	kinematic viscosity
$\nu_a(t)$	=	CGA rise velocity.
ν_s	=	velocity of the CGA in stagnant water

ϕ = porosity of pack.

1 INTRODUCTION

1.1 OVERVIEW

Declining oil production and stricter environmental regulations have resulted in a search for improved technologies to reduce cost and improve recovery from existing hydrocarbon reserves. One of the most effective methods of cost reduction relies on improvements in drilling technologies, in particular, development of directional, horizontal, and multilateral wells. Many reservoirs in Canada and other areas of the world are partially depleted (low reservoir pressure) and drilling new wells becomes difficult. To effectively drill re-entry horizontal or multilateral wells, one may have to use specially designed drilling fluids to minimize formation damage and increase the rate of penetration. Significant reserve additions or 'reclamation' may be realized if the hazards associated with drilling in sub-normally pressured environments (e.g., lost-circulation and differentially stuck pipe) can be effectively managed.

1.2 BACKGROUND OF THE PROBLEM

Drilling fluid is an imperative component of the drilling operation. The fluid is pumped down the drilling rod, passed through the drill bit and pumped back to the surface via the wellbore. One of the main functions of drilling fluid is to transport the cuttings from the bottom of the well to the surface thus cleaning the face of the rock and allowing for more efficient drilling. Another function of drilling fluids includes suspension of the cuttings when drilling has been stopped. The rheology of the fluid is very important in this aspect because the fluid must be able to build a gel structure to hold the cuttings while not in motion but not so viscous that it is unable to flow. Drilling fluid is also used to offset the pressure exerted by the fluids present in the rock. When a well is drilled, any fluid that is in the formation rock can flow out of the well if there is nothing in the well to offset the pressure exerted by the formation fluid. There is not only a risk of the reservoir fluid flowing into the wellbore but there is also a risk of the formation caving in and the drilling fluid can help to prevent this. If the pressure exerted by the drilling fluid is too high however, the fluid will

invade the formation causing formation damage. Drilling fluid is also used to lubricate and cool the system and to create some buoyancy of the drill pipe to ease the stress on the drilling equipment.

The most common way to drill oil wells is when the drilling fluid pressure is maintained above the formation pressure. This is known as overbalanced drilling. If the difference between the drilling fluid pressure and the formation pore pressure is too high, it can cause some problems such as formation damage, differential pipe stuck where the drill pipe becomes suctioned to the thick mudcake at the face of the wellbore and even fracturing of the formation. In an attempt to eliminate these problems, underbalanced drilling was developed.

Underbalanced drilling uses a fluid that maintains a pressure in the wellbore that is less than the formation pressure. This method eliminates the loss of fluid into the formation and formation damage. Because formation damage is eliminated, production can be accomplished earlier. It also allows formation fluid to be produced while drilling thus identifying payzones in a quicker manner. As well, since the fluid is less dense and there is less pressure at the bit while drilling, drilling rates are increased as well as the life of the bit. One problem with underbalanced drilling is borehole instability since the pore pressure is greater than the drilling fluid pressure. As well, drilling underbalanced requires specialized equipment to create foams and removal of the cutting can be an issue because of the high penetration rates. Finally, because of the underbalanced situation, there is a great risk of blowouts than there is when drilling overbalanced.

1.3 STATEMENT OF THE PROBLEM

Underbalanced drilling is not feasible due to economical (e.g. requires special equipment) and/or technical (e.g. wellbore instability) reasons in many situations. At-balance drilling where the pore pressure gradient closely matches the mud density, can eliminate both borehole instability and formation damage and is a feasible alternative to underbalanced drilling.

When drilling at-balance, the fluid density is designed to be close to formation pressure gradient, but not so low that formation fluids enter the wellbore. The density of fluid is greater than the pore pressure gradient but not so high that it will create any fluid influx into the formation.

Applications of at-balance drilling technologies calls for the use of special drilling fluids, one of which is colloidal gas aphron (CGA) based. CGAs have been successfully utilized in pilot field applications. This success has been due to the fact that the CGAs have the unique ability to form a bridge in the pores of the reservoirs which stops fluid invasion. Commonly, the bridging mechanism is explained through the Jamin Effect which describes the pressure needed for one non-wetting fluid to push a wetting fluid in capillary space. Due to the complexity of the aphron structure and nature, it is unknown under exactly what conditions this effect takes place. As well, it is unknown if this mechanism accurately describes the bridging mechanism. The Jamin Effect describes actions in capillary space. When the pores are larger than a capillary size, the theory may not be valid. Validation of this theory is of extreme importance since the bridging mechanism is the strength of the system.

This study focuses on developing a better understanding of the bridging mechanism involved with CGA based drilling muds. Understanding the bridging mechanism leads to the study of the Jamin Effect, a theory that has been used in the past to describe the bridging mechanism. The factors that control the pore blocking ability of CGA based fluids including CGAs size, pore size and the interaction between the CGA fluid and the formation fluids is investigated. Visualization of the pore blocking process is also attempted. Through this, a better understanding of the bridging mechanism as well as the types of reservoirs that can be successfully drilled with this fluid is determined.

1.4 OBJECTIVE AND SCOPE OF THE STUDY

The primary purpose of this study is to develop a better understanding of the physicochemical properties of CGA based drilling fluid and the CGA pore blocking mechanisms. The study will deal with both experimental and modeling aspects. This study has been divided into the following objectives:

1. Investigate the generation methods for CGAs.
 - Identify proper mixing equipment and technique that could be used for the generation of CGAs.
 - Investigate previous mixing devices and surfactants utilized to generate CGAs.
 - Identify surfactants that could be used to form stable microbubbles.
2. Investigate the bulk characteristics of various compositions and stability of CGA based drilling fluids.
 - Investigate viscosity, density and filtration loss characteristics of the CGA based drilling fluids.
 - Determine the effect of surfactant concentration, polymer concentration, surfactant type, shear rate, mixing time and water quality on the rheology and stability of CGA fluid.
 - Investigate the effect of pressure and temperature on the bulk CGA fluid rheology and stability.
 - Study the change in CGA bubble diameter with time, pressure and temperature.
3. Study the mechanisms of CGA bridging, in particular the Jamin Effect, and its effectiveness of controlling fluid filtration rate under various conditions.
 - Conduct visualization study of CGA flow through porous media using micromodels.

- Conduct core flow experiments to determine pore blocking ability and formation damage characteristics of CGAs.
 - Study the effect of permeability and wettability on the pore blocking ability and formation damage characteristics of CGAs.
 - Study the effect of pore fluid type on the blocking ability of CGAs. Water, brine, mineral oil and crude oil are the fluid types used in these experiments.
4. Develop a prediction method for CGA size, stability and blocking ability.
- Two models, the drainage model and the bubble break-up model have been studied.
 - Investigate the models that could be used to predict the stability of CGAs
 - Models that could be used to predict the CGA size under increasing pressures and temperatures are developed.
 - Develop equations of state for CGAs

Four journal publications and one conference proceeding have been currently published through this study (Bjorndalen et al., 2008; Bjorndalen et al., 2009; Bjorndalen et al., 2010; Bjorndalen and Kuru, 2008a; Bjorndalen and Kuru, 2008b)

1.5 STRUCTURE OF THE THESIS

The organization of the thesis is as follows.

Chapter 1 provides the introduction to the thesis. It includes sections on the objectives, scope of the work and statement of the problem.

Chapter 2 is the literature review and it describes the work by previous authors on CGAs. It also provides background information on the proposed experiments.

Results of the CGA generation and characterization experiments including bulk density, rheology and API filtration measurements are provided in Chapter 3.

Chapter 4 presents the results of the investigation of the factors controlling colloidal gas aphron stability.

CGA bubble size characterization is discussed in Chapter 5. Results of the experiments on the effect of time, pressure and temperature on the bubble size are provided in this chapter.

Chapter 6 presents the results of visualization study of CGA flow through porous media.

Results of the experiments investigating CGA flow through porous media by using sandpack are provided in Chapter 7.

Chapter 8 describes the method developed for CGA size prediction.

Chapter 9 contains the conclusions and recommendations.

Chapter 10 provides the references.

2 LITERATURE REVIEW

At-balance drilling is a method that eliminates the problems associated with under and overbalanced drilling. In order to achieve an at-balance drilling situation, a fluid must be utilized that will eliminate the pressure differential between the borehole and the reservoir. The fluid density is maintained at a level greater than the formation pressure but is small enough not to invade the formation (Edwards et al., 2003). Colloidal gas aphron drilling fluid simulates such a situation by building a bridge in the fractures and pores of the reservoir. This bridge stabilizes the formation while allowing minimal damage to the formation. This system has been successfully implemented in high-angle and horizontal well drilling in highly depleted reservoirs (Brookey, 1998) as well as with vertical wells. A recent study showed that when compared to a centrifuged diesel mud, the CGA system reduced the cost of drilling one well by 44% (Rea et al., 2003).

Simply put, aphrons are bubbles, approximately 10 – 100 microns in diameter. Originally termed as microbubbles because of the size the name was later changed to Colloidal Gas Aphrons (CGA) because of they exhibit some colloidal properties (Sebba, 1987). CGAs are extremely stable in drilling fluid at lower pressures. Above a critical pressure, the CGAs will collapse. For this reason, concerns have been raised as to the widespread application of this system (Reid and Santos, 2003) but CGA drilling fluid systems have been used in mature fields. Visualization tests indicate that CGAs can be maintained at pressure of at least 1500 psi (Ivan et al., 2002). CGAs are non-coalescing, can be re-circulated and are not affected even by fine screen shale shakers. Downhole tools can be utilized with the CGA mud system. CGAs eliminate differential sticking by altering the near wellbore pressure drop (Rea et al., 2003), which in turn reduces the need for costly downhole tools in low-reservoir pressure applications (Oyatamari et al., 2002). One of the most important assets of the colloidal gas aphrons is that it can resist compression and expansion because it is self-contained. With this system there is no need for injection of gases since CGAs can be produced easily at the

surface with mixing equipment. As well, unlike aerated mud, CGA drilling fluid will not corrode the drillstring since most of the air in the system is encapsulated in the CGA shell (Brookey, 1998).

2.1 COLLOIDAL GAS APHRON STRUCTURE

Like regular foams, aphrons are typically composed of a gaseous (Colloidal Gas Aphrons) or liquid spherical (Polyaphron) core. Unlike foams, aphrons have a thin aqueous protective shell. The aphron is composed of an inner shell as well as an outer shell. Figure 2-1 illustrates the structure of the aphron on a molecular level. The two shells are separated by a viscous water phase. The inner shell consists of surfactant molecules that are hydrophobic inwards and hydrophilic outwards. This layer supports and separates the air core from the viscous layer. The outer shell which also supports the viscous layer is hydrophobic outwards and hydrophilic inwards. Since this bubble is in contact with the bulk water it is only natural to believe that there is another layer in which the surfactant molecules are hydrophobic inwards and hydrophilic outwards. This indicates that there is a region in between the aphron outer shell and the bulk phase layer where a

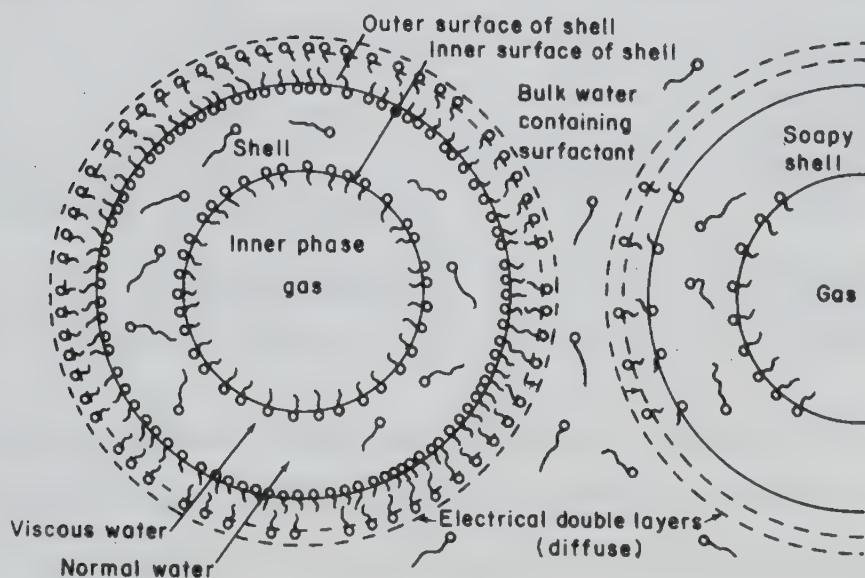


Figure 2-1: Structure of a CGA (Sebba, 1987)

hydrophobic globule will be comfortable and adhere to the gas aphron (Sebba, 1987). Extending this theory leads to the concept that the aphron can act as a non-wetting phase while still being maintained in a wetting phase.

2.2 COLLOIDAL GAS APHRON COMPOSITION

Table 2-1 shows the typical composition of water-based CGA drilling fluids. The components include a viscosifier, surfactant and fluid loss control additive. The function of each component is given in the table as well. The mud is designed to generate the desired concentration of air which is between 8 and 15% v/v under ambient conditions (Growcock et al., 2003). Due to the high level of surfactant utilized, some believe that formation clean-up can be difficult (Reid and Santos, 2003) although field experiences have disputed this belief (Kinchen et al., 2001).

Table 2-1: Typical composition of water based CGA drilling fluid. (*) denote the optional components (Ivan et al., 2002; Ivan et al., 2003; Growcock et al., 2003).

Component	Function	Formulation
Base Fluid (fresh water or brine)	Provides continuous phase for system	0.97 bbl/final bbl
Soda Ash	Hardness buffer	0.25 lb/bbl
Biopolymer Blend	Viscosifier	5.0 lb/bbl
Polymer Blend	Fluid-loss control and thermal stabilization	5.0 lb/bbl
pH Buffer	pH control	0.5 lb/bbl
Surfactant	Aphronizer	1.0 lb/bbl
Biocide	Biocide	0.05 gal/bbl
Polymer/Surfactant Blend*	CGA Stabilizer	1 lb/bbl
Polymer*	Shale Inhibitor	1 lb/bbl
Oligomer*	Defoamer	1 lb/bbl

The main component needed to generate the CGAs is a surfactant. A summary of the surfactants utilized to generate the CGAs by different researchers is given in Table 2-2. It is evident that there are many chemicals available that can be utilized. The surfactant that is used should be decided upon when drilling mud compatibility has been taken into account.

Table 2-2: Summary of materials utilized for generation of colloidal gas aphrons.

Reference	Type	Surfactant	Amount
Amiri and Woodburn, 1990	Cationic	Tetradecyltrimethyl ammonium bromide (TTAB)	0.975 g/ dm ³
Roy et al., 1992a	Anionic	Sodium dodecyl benzene sulfonate (DDBS)	500 ppm
	Cationic	Hexadecyltrimethyl ammonium bromide (HTAB)	350 ppm
Roy et al., 1995b	Nonionic	Tergitol	-
	Cationic	Hexdecyltrimethyl ammonium bromide (HTAB)	-
	Anionic	sodium dodecyl sulfate (SDS)	-
Jackson et al., 1998	Anionic	Sodium dodecyl benzene sulfonate (DDBS),	500 ppm
Jauregi et al., 2000	Anionic	Sodium bis-(2ethyl hexyl) sulfosuccinate (AOT)	0.4 L of a 1 L total solution
Dai and Deng, 2003	Cationic	Hexdecyltrimethyl ammonia chloride (HTAC)	9.2 x 10 ⁻⁴ mol/dm ³

The word surfactant stands for surface active agent. The basic meaning of the word surfactant is a material that has the ability to alter interfacial interaction through enhanced adsorption at that interface (Myers, 1988). The interfacial interaction focused on here will be on the liquid-vapour interface where the vapour in question is air and the liquid in question is water. A surfactant's structure is unique in that there is a molecular group that has an affinity to the bulk or liquid phase namely lyophilic and a molecular group that dislikes the bulk or liquid phase namely lyophobic. When discussion turns to water as the bulk phase the lyophilic group is named hydrophilic and the lyophobic phase is named hydrophobic. Figure 2-2 illustrates the basic structure of the surfactant molecule.

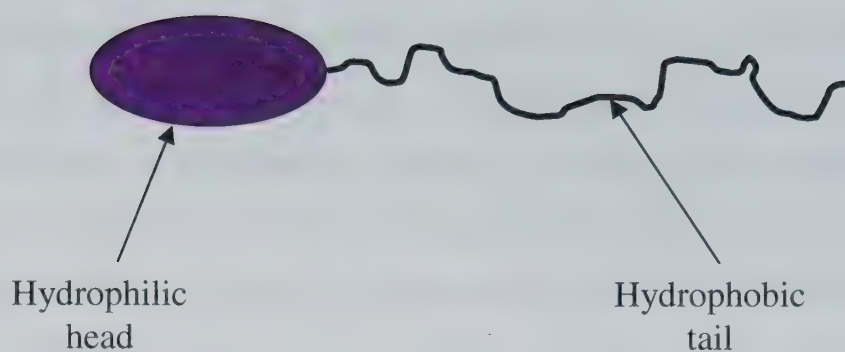


Figure 2-2: The basic chemical nature of the surfactant molecule (After Myers, 1988)

The most common chemical classification of surfactants is based upon the nature of the hydrophilic group. The hydrophilic group is usually highly polar and the hydrophobic group usually consists of a long chained hydrocarbon radical. The four most common chemical classifications are anionic where the hydrophilic group has a negative charge, cationic where the hydrophilic group carries a positive charge, nonionic where the hydrophilic group has no charge and amphoteric where the hydrophilic group has the potential to contain both positive and negative molecules. Anionic surfactants are the largest group of surfactants. Subgroups of this class include alkali, carboxylates, sulfates, and sulfonates. Commonly, cationic surfactants are used in cosmetics as antiseptic agent and are added to crude oil to protect against corrosion. Nonionic surfactants are useful when the pH of the system becomes an issue. Amphoteric surfactants function very similarly to the nonionic group. This group also can be combined with other surfactant groups and are quite useful in applications requiring biological contact such as no tears baby shampoo (Myers, 1988).

When surfactants encounter an interface, it will adsorb to that interface at low concentrations of the surfactant. This adsorption will result in a replacement of the higher energy bulk phase molecules and will therefore reduce the free energy of the boundary. Resulting in a reduction of the work needed to expand the interface. In other words, the surfactant will reduce the interfacial tension. At this point the surfactant molecules are known simply as monomers meaning that they are individual surviving in the mixture. If more surfactant molecules are

added to the bulk phase, the reduction of interfacial tension will continue until a point where the surface will be packed with surfactant molecules. At this point, micelles will form in the solution. The concentration of the surfactant in the mixture at the point where the nature changes is known as the Critical Micelle Concentration (CMC). Figure 2-3 illustrates this process. The hydrophobic tails completely fill the center of the sphere and the size of the micelle is approximately double the length of the surfactant molecule. As the surfactant concentration increases further, the spheres accumulate into rods and as the liquid in the system becomes less and less, the rods form layers. This process, although theoretically correct, rarely happens in reality since the process is based on identical surfactant molecules. Commercial surfactants rarely have the exact same length of hydrophobic tails and mixed micelles are more common (Hargreaves, 2003).

For stability of the CGA, the concentration of the surfactant should be greater than the critical micelle concentration (CMC) (Roy et al., 1992a, Longe 1989) which varies for each type of surfactant. When a concentration of less than the CMC is used, the CGAs will be large in size (Longe, 1989). Measuring the CMC can be achieved through surface tension measurements. Figure 2-4 shows a simplified version of the surface tension versus surfactant concentration. From the figure, when the concentration of surfactant is low, an increase in the concentration will decrease the surface tension. At the CMC and beyond, the surface tension will no longer change with concentration. The CMC for some of the surfactants utilized to build CGAs has been reported in literature. For example, the CMC of hexadecyltrimethyl ammonium bromide (HTAB) in water is approximately 350 ppm and for sodium dodecyl benzene sulfonate is approximately 500 ppm (Roy et al., 1992a).

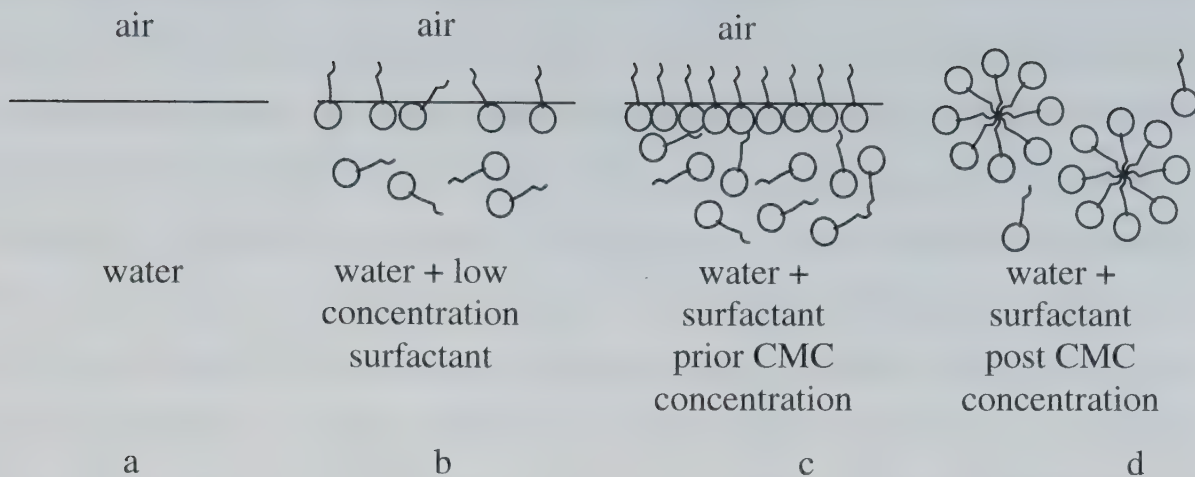


Figure 2-3: Micelle formation. a) before adding the surfactant. b) at low concentrations of surfactant. c) right before the CMC has been reached. The surface is saturated with surfactant molecules. d) after the CMC, the formation of micelles.

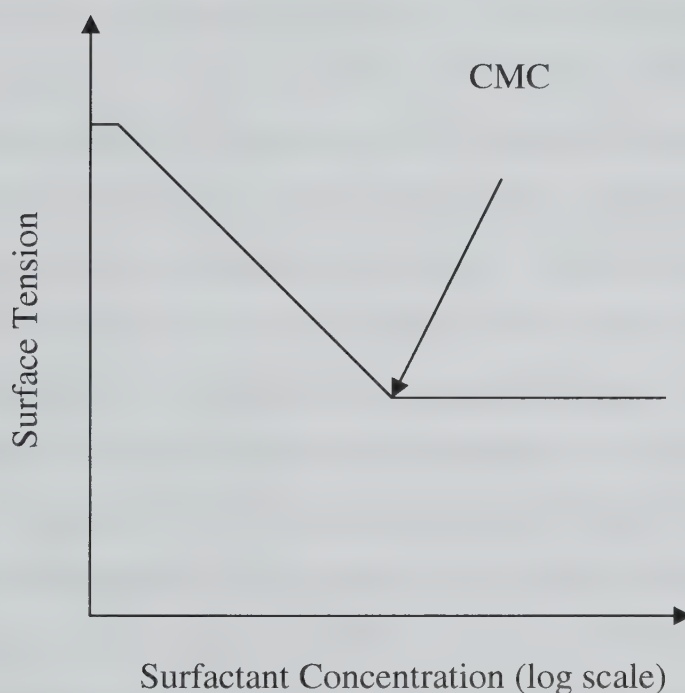


Figure 2-4: Simplified determination of CMC

2.3 COLLOIDAL GAS APHRON GENERATION

A method for the generation of the CGAs was first described by Sebba (1985; 1987) and since then, variation of this method has been utilized to successfully generate CGA mixtures (Wan and Tokunaga, 1999; Jauregi et al., 1997, 2000; Dai

and Deng, 2003; Save and Pangarkar, 1994; Chaphalkar et al., 1993; Roy et al., 1992a, 1994; Amiri and Woodburn, 1990). Figure 2-5 shows the CGA generator developed by Sebba. A disc, rotated at 4000 rpm, is used to mix the solution. Baffles are also situated in the beaker containing the solution and are attached to a stirring rod. As the fluid is rotated, the baffles act to add turbulence between the fluid and the air at the surface. This air is then encapsulated in the fluid and CGAs are formed. The CGAs are extracted from the solution via a tube at the edge of the beaker. Longe (1989) examined the design considerations for CGA generation. It was stated that there are three components which are needed for the generation: a holding vessel, a shearing device and baffles. The baffles, although not vital, are recommended if a CGA of a size less than 100 microns is required. It was also stated that the baffles should be situated in the beaker such that they are not too close to the beaker wall nor too far away. If the baffles are too close to the wall, air induction is inhibited. In Longe's set-up, the baffles were 1.9 cm away from the vessel wall. Roy et al. (1992a, 1994) and Chaphalkar et al. (1993) designed their CGA generator with a 50 mm diameter flat disc as the mixer and a 3 Litre cylindrical container. Two baffles were attached to the lid of the container and the disc was rotated at 8000 rpm. Wan and Tokunaga (1999) also used a 50 mm disc and two vertical baffles. The solution was contained in a 4.5 Litre beaker and the rotational speed was 16000 rpm. A pressurized system of up to 340 kPa was also possible as this generator was encased in a steel chamber. Save and Pangarkar (1994) modified the set-up by utilizing a propeller instead of a disc and omitting the baffles. Jauregi et al. (1997, 2000) used a four baffle system and combined this with a four blade vertical impeller that was surrounded by a high shear screen. Dai and Deng (2003) utilized a central agitator consisting of four blades. A bolt sleeve with 1 mm perforations encompassed the blades for ease of gas and water flow. The system was also equipped with 2 baffles.

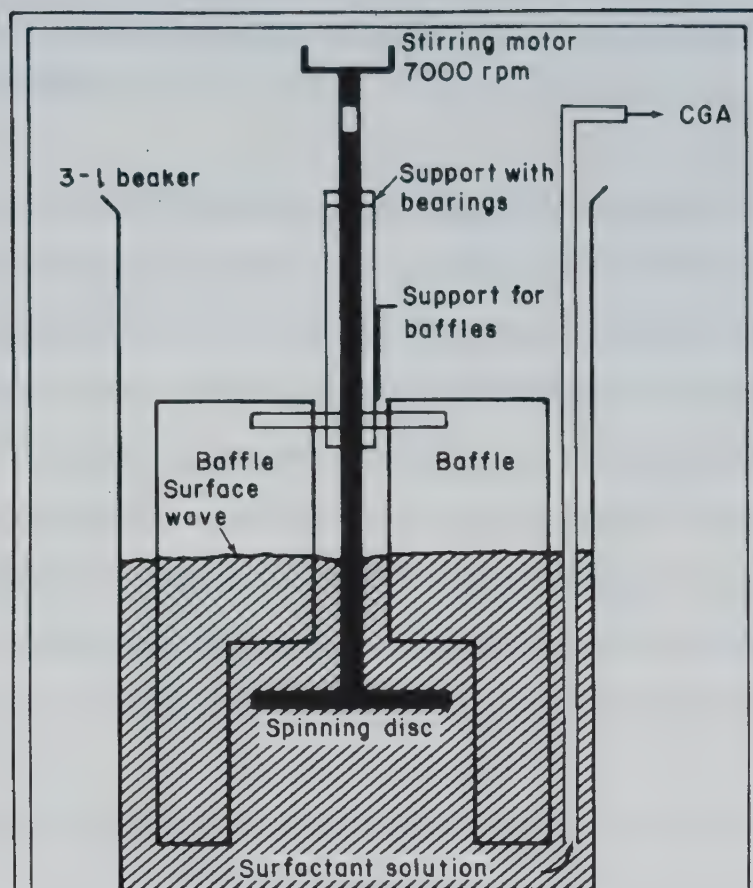


Figure 2-5: Spinning disc Colloidal Gas Aphron generator (Sebba, 1987)

2.4 COLLOIDAL GAS APHRON STABILITY

Stability of the CGAs and how bubble size changes as a function of downhole conditions (i.e., temperature and pressure) are some of the major concerns associated with the application of CGA based drilling fluids. A stable CGA structure requires maintaining an ideal film wall thickness of 4 to 10 micron (Clunie et al., 1967). Another factor affecting CGA stability is the rate of transfer of the surfactant molecules between the viscous water shell and the bulk phase due to gravity drainage or temperature gradients. This leads to a surface tension gradient at the surface of the shell. As a result, this gradient will be reduced by surfactant molecule moving from low surface tension areas to high surface tension areas. This process is known as the Marangoni Effect. (Mellema and Benjamins, 2004; Tan et al., 2005). Increasing the viscosity of the shell can help to minimize the transfer of surfactant molecules. Usually a biopolymer is added to adjust the shell viscosity (Ivan et al., 2003). The third property that the CGA structure must

have is low diffusivity, which is the ability of the air that is in the core to transfer to the aqueous shell.

CGA bubble size and stability have been the subject of earlier studies (Longe, 1989; Jauregi et al., 1997; Chaphalkar et al., 1993; Roy et al., 1992a; Amiri and Woodburn, 1990; Save and Pangarkar, 1994; Dai and Deng, 2003). Longe (1989) analyzed the bubble size distribution of CGAs for soil and groundwater decontamination applications. Longe's analyses included effects of surfactant concentration, surfactant type and electrolytes on the stability of the CGAs over the time. Jauregi et al. (1997) also investigated the stability of CGAs as a function of surfactant concentration. Results from both studies indicated that the stability of CGAs increases with increasing surfactant concentration.

Chaphalkar et al. (1993) measured the size distribution of CGAs using a particle size analyzer. It was found that for three different types of surfactant, the CGAs were virtually non-existent after 20 minutes. Roy et al. (1992a) reported similar results.

Amiri and Woodburn (1990) studied the rate of drainage as well as the CGA bubble size by recording images of the CGAs with time. They showed that after 10 minutes, the bubble shape had changed from spheres to polyhedral structures. Save and Pangarkar (1994) analyzed the half life of CGAs by measuring the rate of drainage as a function of various parameters including the effect of viscosity. They showed that increasing viscosity also increased the half life of the CGA. This effect was attributed to the fact that higher viscosity slows the drainage rate and, hence, reduces the bubble film deformation rate.

The increase in mean diameter of CGA based solution was observed by Dai and Deng (2003) for stabilized and unstabilized CGA solutions. The CGA solution was stabilized by injecting it into a silicic gel solution. It was found that the

stabilized CGAs maintained their size for more than 700 minutes while the unstabilized CGAs doubled in size in less than 100 minutes.

The stability of CGA drilling fluids was studied by Growcock (2005). It was determined that in the fluid composition used to generate the CGAs, the oxygen core was scavenged by cellulosic polymer leaving behind a nitrogen core and reducing the CGA size by approximately 7%. It was also found that the CGA fluid is more stable than a conventional bubble.

CGAs are stable in drilling fluids at lower pressures. Above a critical pressure, the CGAs will collapse. Since the CGAs collapse at higher pressures, concerns have been raised as to the widespread application of this system (Reid and Santos, 2003) but the CGA drilling fluid systems have been used in mature fields (Ramirez et al., 2002). A collapse pressure of 3000 psi was used by White et al. (2003) when running simulations that determined the CGA concentration and bubble size with an increase in pressure. Visualization tests indicated that CGAs can be maintained at pressure of at least 1500 psi (Ivan et al., 2002). Growcock et al. (2003) stated that even at pressure near 2000 psi, the air core will not diffuse into the liquid phase. Growcock (2005) showed that there is a critical bubble size for which the bubble will collapse. They stated that bubbles between 20 and 50 μm are more susceptible to collapse under pressure increase intervals. The pressure interval used for this study was 500 psi. Growcock (2005) also concluded that the rate at which the pressure is applied does not have an effect on the stability of the CGA.

Holt et al. (1996) and Liu et al. (2005) examined foam stability under high pressure. Holt et al. (1996) stated that with an increase in pressure, the surface tension of the surfactant mixture decreases and that this increased the foam stability through an increase in surfactant adsorption on the surface of the interface. Liu et al. (2005) studied CO_2 foam and found that with an increase in

pressure foam stability decreased. It was concluded that the stability of the foam under pressure depends on the nature of the foam.

The stability of foam under high temperatures was investigated by Liu et al. (2005). Similar to the effect of pressure, temperature effect depend on the nature of the system studied although common theory is that with an increase in temperature, the surface tension decreases and the foam stability increases. For the CO₂ system studied by Liu et al (2005) foam stability was not affected under 60°C and above 60°C, foam stability decreased.

Longe (1989) studied the effect of temperature on CGAs and found that the CGAs were relatively stable at temperatures below 40°C and fully unstable at temperatures above 65°C.

2.5 COLLOIDAL GAS APHRON BRIDGING MECHANISM

When the pressure of the drilling fluid is greater than that of the formation the CGA drilling fluid will then invade the formation (vugs, fractures and pores) on a micro-level and expand due to the pressure drop. As well, the pressure in the wellbore will cause more CGAs to invade the formation. It has been hypothesized that an aggregate of CGAs will form and will cause an increase in Laplace Pressure (Brookey, 1998). Since the aggregate will act as one bubble, Laplace pressure will increase because the radius of the bubble has increased (ie. one bubble radius vs. an aggregate radii). This aggregate will build a solid free bridge which can be removed by a change in hydrostatic pressure. This solid free bridge reduces the drastic pressure changes that are apparent when a regular filter cake is present. This reduction in the drastic pressure drop reduces the risk of differential pipe stuck. However, Growcock (2005) found that CGA's have very little affinity for each other and therefore do not aggregate.

Although CGA flow and blockage in porous media has not been studied extensively, foam flow in porous media has been investigated (Smith et al., 1969;

Albrecht and Marsden, 1970; Hanssen and Dalland, 1990; Aarra and Skauge, 1994; Nimir and Seright, 1996; Khalil and Asghair, 2006). Much of this research has focused on foam injection for enhancing oil recovery. As well, there is a large focus on the creation of foams in the porous media itself (Yang and Reed, 1989; Sanchez and Hazlett, 1992). Bernard and Holm (1964) studied the effect of foam on the reduction of gas permeability. Bernard et al. (1965) studied the effect of foam on the reduction of water permeability. They found that foam effectively plugged the gas flow in the reservoir. Albrecht and Marsden (1970) studied foam blocking and found that with an increase in surfactant concentration, the blocking effect was greater. The efficiency of foams to block gas propagation in porous media with crude oil was studied by Hanssen and Dalland (1990). They tested many different surfactants and found that there was no correlation between gas blocking and interfacial tension and that only a few foams blocked the samples tested. They stated that the foam blocking is a complex phenomenon. Manlowe and Radke (1990) investigated the effect of oil on foam stability in porous media using an etched glass model. They found that the lack of stability of the foam when in contact with oil is determined by the strength of the film in between the bubble and the oil. Aarra and Skauge (1994) and Aarra et al. (2002) tested foams for gas mobility control in the North Sea with successful results. Nimir and Seright (1996) compared the placement efficiency of foams to gels as blocking agents in various cores ranging in permeability from 7.5 to 900 mD. They used a C_{14-16} α -olefin sulfonate and found that the foam was a better blocking agent when the low permeable zone is less than 7.5 mD and the high permeable zone is more than 80 mD.

Foam gel combinations have also been studied to enhance blocking ability. (Wassmuth et al., 2000; Romero and Kantzas, 2004; Romero-Zeron and Kantzas, 2003; 2006; Asghari et al., 2005). Romero-Zeron and Kantzas (2003; 2006) and Romero and Kantzas (2004) discussed the microlevel placement of polymer/synthetic brine based foamed gel and change in the foam during gelation for blockage of gas and water during oil production. It was found that the bubble

growth with time inside the porous media was greater in water-wet situations than in oil wet situations which may be due to the adsorption of surfactant in water-wet cases (Romero and Kantzas, 2004; Romero-Zeron and Kantzas, 2006). Gelled foam was suggested as a viable use for the remediation of wormholes in cold production (Asghari et al., 2005). Wassmuth et al. (2000) investigated the blocking ability of polymer enhanced foam and foam gels. They found that with an increase in the polymer viscosity, the blocking ability increased. Dalland and Hanssen (1997) also compared foams, polymer enhanced foams and foam gels. They found the polymer enhanced foams increases the gas blocking ability but that at high concentrations of polymer, the blocking efficiency can be reduced.

Holm (1968) attempted to study the microflow of foams in porous media. It was found that the flow rate of liquid is less when foam is present. It was also found that small bubbles will coalesce at the entrance of a restriction and foam will break and form small bubbles at the outlet of a restriction. As well, it was concluded that even when foam was injected directly into the porous media, the gas and liquid phases flowed as two separate phases through the media. The gas bubbles coalesce and reform while the liquid flowed via the bubble film. Mast (1972) also found that the gas bubbles broke down and re-formed but only when the foam was unstable. When stable foam was used, the foam flowed through the porous media as one unit.

In 1992, Osterloh and Jante studied the flow regime of foam. They found two different regimes in which the pressure gradient in high quality foam flow is independent of gas flow rate and the pressure gradient in low quality foam is independent of liquid flow rate. Alvarez et al. (2001) confirmed these flow regimes for various gases, porous media and surfactants. Romero et al. (2002) conducted a micromodel study of the flow regime of polymer enhanced foams (PEF) in constricted capillaries. They found that polymer enhanced foams did not exhibit the high quality flow regime. They suggested that the flow of PEF may not be governed by capillary pressure and coalescence. Alvarez et al. (2000)

determined that foams in the low quality flow regime were better for acid diversion.

Mast (1972) used an etched glass model to study the flow of foam through porous media. It was discovered that the foam blocked some of the pore throats and it was concluded that this was due to Jamin action. Owete and Bringham (1987) also concluded this. The average bubble size was as large as or larger than the pore size. Blockage was temporary and it occurred in the smaller flow channels only.

A limited study on the flow of CGAs in porous media has been presented by Growcock et al. (2006). They included the visualization of aphrons in a microcell but did not provide any visualization of plugging or a quantitative pressure range for the experiment.

2.6 JAMIN EFFECT

The foam blockage or bridging mechanism can be described through the Jamin Effect. The Jamin Effect or as it is sometimes referred the Jamin Action was initially described by Jamin (1860) as the resistance caused by the boundary conditions of gas and liquid bubbles in a confined capillary space (Gardescu, 1930). Basically it describes a non-wetting fluid's resistance to proceed into a pore of a water-wet capillary. Figure 2-6 describes the interaction between a gas and a liquid in a capillary tube where the gas bubble is moving along the tube. The contact angles of the gas bubbles in section 1 and 2 are different since bubble 2 is moving along a dry solid surface and bubble 1 is moving along a wet solid surface. The assumption here is that the capillary is initially dry thus bubble 2 is moving along the dry surface. The liquid phase in section 3 wets the capillary tube and therefore the gas bubble in section 1 is moving along a wet surface. Therefore, the radius of the corresponding menisci (r_1 , r_2) will be different and can be calculated by the following equations:

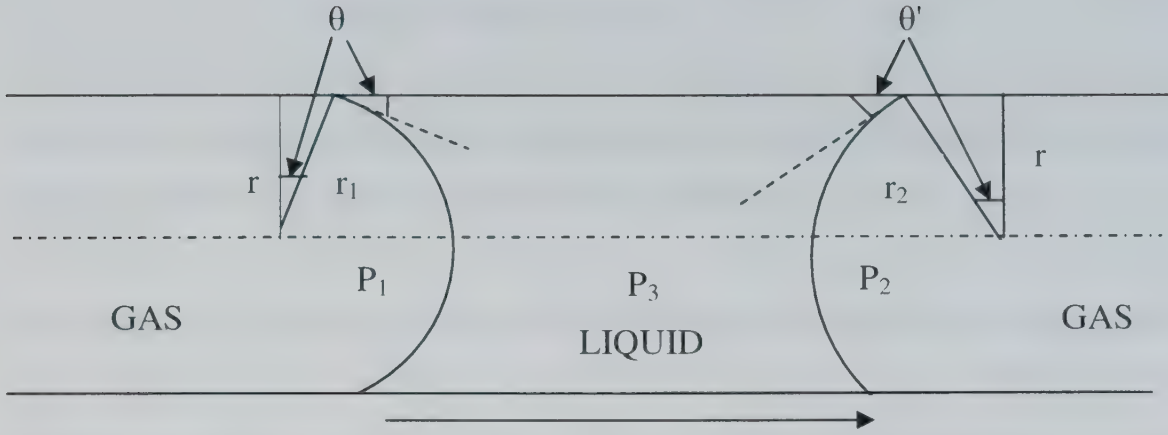


Figure 2-6: Gas and liquid bubbles in a capillary tube (After Gardescu, 1930)

$$r_1 = \frac{r}{\cos\theta} \quad (2-1)$$

$$r_2 = \frac{r}{\cos\theta'} \quad (2-2)$$

where r is the radius of the tube, and θ and θ' are the contact angles of gas bubbles 1 and 2 respectively.

In order to determine the pressure needed to move the gas bubble along the tube, the pressures applied to the interfaces must be defined and are given by Equation (2-3) and Equation (2-4)

$$P_1 = P_3 + \frac{2\delta}{r_1} \quad (2-3)$$

$$P_2 = P_3 + \frac{2\delta}{r_2} \quad (2-4)$$

where P_1 and P_2 is the pressure exerted by the gas bubble, P_3 is the pressure exerted by the liquid and δ is the surface tension between the gas and liquid. Extending this theory to the situation given in Figure 2-7, the pressure needed to move the gas bubble is difference between the pressure at 1 and the pressure at 2.

$$\Delta P = 2\delta(1/r_1 - 1/r_2) \quad (2-5)$$

where ΔP is the resistance of fluid displacement, δ is the surface tension, r_1 is the capillary radius and r_2 is the original radius of the CGA.

In Figure 2-7a, there is no pressure being applied to the bubble or in other words little resistance for the bubble to move into the small opening. The shape of the bubble at this time is a perfect sphere. As a pressure is applied (Figure 2-7b) the bubble invades the reduced opening and the bubble is elongated thus creating two distinct radii. Increasing the pressure even further, the bubble will distort to a greater extent until a point is reached where both radii will be equal and the resistance to move will again be zero (Figure 2-7c). Determining the maximum pressure that can be applied before the radii will become equal is of utmost importance to the bridging mechanism. The average CGA bubble size under atmospheric pressure is in the 10 to 100 μm range depending on the type of surfactant utilized. Typical pore diameters for sandstone can also be found in the 10 to 100 μm range (Howard et al., 1993).

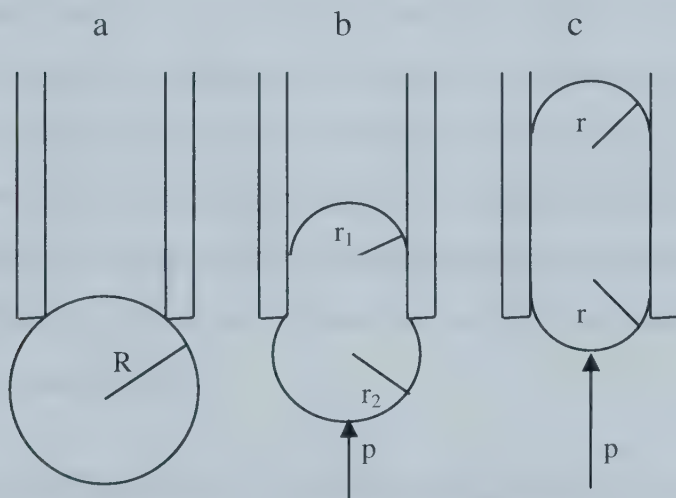


Figure 2-7: Gas bubble being force through restricted space. (After Gardescu, 1930)

Schiegg (1980) studied the Jamin Effect on oil in water emulsions. It was stated that bridging will be achieved if the diameter of the pore throat is smaller than the

diameter of the non-wetting fluid that is maintained in a wetting fluid. In the case of CGAs, the CGA itself acts as the not-wetting phase whereas the fluid which surrounds it (either the water based mud or the fluid in the capillary) acts as the wetting phase. The resistance of fluid displacement may be small for one bubble but it will be very large for an aggregate of bubbles (Lagnes, 1972). The ability of the aggregate to act as a single CGA, meaning with lipophilic characteristics, is due to the “meniscus wrapping theory” which is based on the mechanism known as Laplace Pressure (Ivan et al., 2003). Laplace Pressure is created when, in this case, two hydrophilic surfaces come in contact and produce a plateau border between them. When this border comes into contact with the water-wet fluid, a contact angle will be created and thus a meniscus (Sebba, 1987).

The argument can be made though that since the CGAs are in capillary dimension and if the pores are greater than the dimension of capillary, then the theory based on the Jamin Effect may not apply (Ivan et al., 2003). This could be the case with fractured or highly porous reservoirs. As well, it may be a factor in average porosity reservoir if the hydrostatic pressure drastically reduces the CGA size. The hydrophobicity of the CGA also has an affect on this process and the strength of the electric double layer, which allows the CGA to exist in the water based drilling mud is also in question. Growcock (2005) studied the wettability of a CGA drilling fluid by mixing the fluid with various oils. It was shown that the CGA fluid was very compatible with the oil studied and that mixing the oil with the CGA drilling fluid produced an emulsion that was stable for a small length of time. As well, the fluids were found to be close to miscible and the oil/mud mixture was water wetting.

2.7 BRIDGING CRITERIA BASED ON PARTICLE AND PORE SIZE

Formation damage and particle deposition can be related to CGA pore blocking. Nabzar et al. (1996) and Chauveteau et al. (1998) developed models for predicting formation damage by particle deposits. They outline four basic mechanism

behind formation damage : 1) Surface Deposition, 2) Pore Bridging, 3) Internal Filter Formation and 4) External Filter Cake Formation.

Bigno et al. (1994) and Xiang and Wang (2003) investigated bridging in terms of gravel packs and sand control. Bigno et al. (1994) outlined five pore blocking mechanism. The mechanisms are: a) no interaction in which the particles freely move through the pack, b) pore filling where the particles gradually deposit on the pore space, c) combined internal bridging and single pore blocking where an initial pore is blocked causing a build up of particles, d) shallow internal bridging where the bridging occurs close to the gravelpack face and e) no invasion where there is an absolute stoppage of the invasion. Xiang and Wang (2003) developed an equation to predict the pore size of the gravel pack based on the invading particle size. They suggest utilizing the $1/3^{\text{rd}}:1/7^{\text{th}}$ rule to predict invasion.

The $1/3^{\text{rd}}:1/7^{\text{th}}$ rule is based on the work which was first described by Abrams (1977). The rule was outlined for selecting the size of bridging materials as: the median particle size of the bridging additive should be equal to or slightly greater than $1/3^{\text{rd}}$ of the median pore size of the formation. Wang et al. (1992), Luo and Luo (1992) and van Oort et al. (1993) later suggested another two rules which state that particles smaller than $1/3^{\text{rd}}$ but greater than $1/7^{\text{th}}$ of the pore diameter will invade the formation and become trapped. Particles less than $1/7^{\text{th}}$ will cause no formation impairment. Van Oort et al. (1993) confirmed that this rule holds true for invasion velocities exceeding 10 cm/min but they also suggested that the value of $1/7^{\text{th}}$ should be decreased to $1/14^{\text{th}}$ for low invasion velocities.

Suri and Sharma (2004) pointed out that it is important to size the particle within a desired range and that using particle that are too large will result in an inefficient bridge and can lead to the invasion of smaller particles thus reducing permeability. Zain and Sharma (1999) and Zain et al. (2000) found that formation damage strongly depends on the particle size distribution.

In order to determine under which conditions the CGA fluid will block the porous media during the drilling process, both the CGA diameter and the pore diameter must be identified. Visualization studies in association with core flooding tests will then be used to further determine and understand the bridging mechanism.

2.8 COLLOIDAL GAS APHRON DIAMETER

During the past decade, CGAs have been studied in the chemical and environmental industries with a focus on the application of soil remediation (Roy et al., 1995b; Jackson et al., 1998; Roy et al., 1992b; Roy et al., 1995a) and aqueous separation (Roy et al., 1992a; Hashim et al., 1995). Through this work, the size of the CGA has been studied by many methods. Parthasarathy et al. (1991) looked at bubble break-up equations for prediction of CGA diameter. Jauregi et al. (2000) used a light microscope, a CCD camera and image analysis to determine the size of the CGA generated. The average diameter recorded was between 32 and 72 μm and there was no trend observed when the surfactant or pH was varied. Dai and Deng (2003) found a mean diameter of 55.02 μm . Photographic techniques have been also used by others (Bee et al., 1986; Basu and Malpani, 2001). Roy et al. (1992a) used a Particle Size Analyzer to determine the size distribution. A laser beam is projected through a transparent cell and the angle of the beams diffraction through the particle is measured. The particle size is directly proportional to the diffraction angle. It was determined that the average size of CGA created from 350 ppm of hexadecyltrimethyl ammonium bromide (HTAB) was 125 μm and from 500 ppm of sodium dodecyl benzene sulfonate (DDBS) was 88 μm . The bubble volume to total volume also decreased during the 14 minute experiment. This was attributed to the very small (less than 25 μm) CGAs disappearing due to the pressure in the liquid. Chaphalkar et al. (1993) utilized the same equipment to determine the size distribution in a dynamic CGA fluid. It was found that the mean diameter of the three different types of CGAs generated was fairly constant with time. The size of CGAs in a highly diluted drilling fluid has been measured using an Acoustic Bubble Spectrometer (White et al., 2000; Growcock et al., 2003). The majority of

the CGA have a diameter of around 30 μm and no bubbles were formed that were less than 26 μm in diameter.

Chaphalkar et al. (1993) discovered that in general an increase in the surfactant concentration increases the stability of the CGAs and an increase in surfactant, decreases the mean diameter of the CGAs. This happens because the surfactant molecules will crowd the molecules on the surface of the CGA causing a decrease in surface tension and the bulk water which will in turn reduce the bubble size.

2.9 PORE DIAMETER

The radius of the interconnecting pore must be known in order to examine the blocking ability. Blockage of pores has been studied by many through the subject area of drilling (Abrams, 1977; Cargnel and Luzardo, 1999) and for production (Barkman, and Davidson, 1972; Al-Abduwani et al., 2000).

The pore radius of a sand pack can be determined through mathematical means if one assumes that the pack and grain diameter are homogeneous. Leontaritis (2005) derived a relationship between hydraulic pore radius (approximate mean pore size) (r_H) and sand grain diameter (d_g).

$$r_H = \frac{\phi}{(1-\phi)} \frac{d_g}{6} \quad (2-6)$$

where ϕ is the porosity of pack.

2.10 VISUALIZATION TESTS

The uses of micromodels for the visualization of fluid flow through porous media is quite widespread (Coste et al., 2000; Romero et al., 2002; Hornbrook et al., 1991; Mast, 1972; Mueke, 1979). Coste et al. (2000) and Al-Sharji et al. (2001) used a micromodel to investigate the flow of plugging particles through porous

media. Hornbrook et al. (1991) constructed a micromodel that closely matched a Berea sandstone core. A picture of a thin slice of core was taken. The picture was then used to etch the silica with the pattern. Although the etched pattern closely matched the Berea sandstone's flow pattern, some manipulation had to be made in order to obtain a well defined flow path. The micromodel was used to study the effect of oil on foam displacement processes. Some of the potential problems with utilizing this type of micromodel was outlined by Sarathi (1986). The problems included: changing etch depth along the flow path, lack of microscopic heterogeneity, and loss of three-dimensional continuity.

Although etched glass is the most common type of micromodels, other types are also used. Romero et al. (2002) investigated polymer enhanced foam flow in porous media with a micromodel composed of capillary tubes of approximately 70 μm in depth and 7 cm in length. The porosity of the model was 0.5. Muecke (1979) used a micromodel of porous media packed between two glass plates to examine the flow of fines. It was found that both the wettability of the particles and the flow rate of fluids as well as the pore size and the concentration of the fines influenced the blockage of pores. Holm (1968) used a glass tube filled with sand grains to study the foam flow. Nguyen et al. (2000) summarized some of the micromodels used for foam flow and listed the typical properties of the models in Table 2-3.

Growcock (2005) conducted two different visualization tests with CGA drilling fluid. Both tests were conducted in a glass bead type pack. The first set of experiments were conducted in an acrylic pipe and the second set was conducted in a radial flow apparatus. Both experimental set-ups were designed to examine the CGA flow in relation to the bulk fluid. For the radial flow experiments, it was indicated that the initial fluid flow rate into the apparatus was 11 cm/sec but this rate quickly dropped to 1 cm/sec. When comparing this data to other types of drilling fluid, it was found the CGA fluid had an average linear flow rate that was an order of magnitude less than the other drilling fluid indicating the efficiency of

the fluid to block pores. It should be noted however that the fluid used in comparison had a low shear rate viscosity (LSRV) that was half of what the LSRV of the CGA fluid was.

Table 2-3: Summary of properties of typical micromodels (Nguyen et al., 2000)

Characteristic	Value
• Areal dimension (cm)	• 4.4 – 9.8
• Pore sizes (μm)	• 25 – 300
• Permeability (Darcy)	• 0.85 – 473
• Pore volumes (cm ³)	• 0.12 – 0.39
• Porosity (%)	• 30 – 42
• Average depth (μm)	• 100 – 150

2.11 CORE FLOODING TESTS

The purpose of core flood / formation damage tests is to understand the extent of a fluids invasion into the porous medium. This is most commonly done by measuring the permeability of a core before and after drilling fluid has been introduced and comparing the results. The permeability of a core is found by applying Darcy's Law and by measuring the pressure differential along a core at a fixed flow rate. Darcy's Law is given by Equation (2-7) where q is the flow rate (bbl/day), A is the cross-sectional area of the core (ft²), k is the permeability (Darcy), μ is the viscosity of the fluid (cp), ΔP is the change in pressure along the core length (psi) and L is the length of the core (ft).

$$\frac{q}{A} = -1.127 \frac{k}{\mu} \frac{\Delta P}{L} \quad (2-7)$$

Basic mechanisms of formation damage include pores plugging due to solid invasion and the reactivity of clays. The mobility of particles in the formation is strongly dependant on surface and interfacial forces. Sarkar and Sharma (1990) found that core wettability, residual oil saturation and oil and water fractional flow all play a role in determining particle invasion.

Han et al. (2005) outlined the basic experimental methods for determining formation damage: core preparation and permeability determination, drilling fluid invasion, backflush and final permeability measurements. They pointed out that there are many different ways that researchers have accomplished these tasks. For example, the fluid can be forced into the formation via static or dynamic methods, there is no clear time limit for the invasion or backflush processes and there is no clear method of backflushing (constant or variable rate). Marshall et al. (1999) also discussed issues involving repeatability and reproducibility of formation damage experiments. An attempt was made to develop a test procedure that would increase reproducibility. Tests were conducted at different laboratories and it was found that although the reproducibility was somewhat achieved at the individual laboratories in the study, reproducibility between laboratories was not achieved. It was then concluded that caution must be used when evaluating the data obtained from formation damage studies.

Salimi and Alikarami (2006) discussed formation damage in fractured reservoirs using a dynamic formation damage test apparatus. A 12 cm long Hassler type core holder with an overburden pressure applied to it was used as the experimental apparatus. The inlet end was fitted with 2 ports for the circulation of the drilling fluid. The invasion process was performed for 4 hours under dynamic conditions and 16 hours under static conditions. This experiment is similar to that conducted by Tuttle and Barkman (1974). Krilov et al. (1991) studied the effect of particle invasion in formation with an x-ray computer assisted tomography (CAT). Thompson and Fogler (1995) used core flow experiments to study the ability of gel particles to block water production. They used 1 inch diameter, 20 – 30 mD ceramic cores for the test. They later used tracers to determine the flow paths in cores before and after the gels were introduced (Thompson and Fogler, 1997).

2.12 SUMMARY

It is evident that there has been some characterization of CGAs as well as some studies on the use of aphronized drilling fluids. However, there is a lack of knowledge when these two topics are combined. Therefore, it is well accepted that the characterization of CGA drilling fluid is of utmost importance to better understand the pore blocking ability of the fluid. Most of the studies thus far in the oil and gas industry have focused on field tests, however, there is a lack of knowledge of under what circumstances the Jamin Effect occurs with the CGA fluid in the wellbore. Laboratory studies with visualization tests and formation damage tests where the various parameters such as pressure, temperature and pore size are fixed can assist the understanding of when this effect occurs.

3 BULK CGA FLUID CHARACTERIZATION

This chapter describes the experiments and results of the bulk CGA fluid characterization. The investigation includes the generation of the CGA fluid and the materials used to generate the fluid. It also includes an examination of the viscosity, the density and the fluid loss of the bulk CGA fluid.

3.1 EQUIPMENT AND MATERIALS USED FOR THE BULK CGA FLUID CHARACTERIZATION

3.1.1 Equipment Used for CGA Generation

The CGAs are generated using either a Brinkmann Homogenizer Model PT 45/80 or the Polytron PT 6100 Generator. Figure 3-1 is a picture of the Polytron PT 6100 Generator. A standard generator with a flat rotor with 2 rotating and 2 stationary rings was attached to both homogenizers. The fluid is passed into the centre of the tip and pressed between the rotor and the teeth of the stator. This generator has been designed for maximum aeration and turbulence and is recommended for emulsions and suspensions. Figure 3-2 is a picture of the generator. The PT 45/80 homogenizer was initially modified in that a 4-baffle system similar to the one utilized by Sebba (1987). The baffles are attached to the shaft of the generator to assist in the air entrainment. Detailed drawings of the baffle system are given in Appendix A. A comparison was made between CGA bubble size created with the baffled PT 45/80 homogenizer and the non-baffled Polytron PT 6100 Generator. Figure 3-3 shows that there is little difference between the initial bubble size of the baffled system versus the non-baffled system for a similar mixing rate. Therefore it was concluded that the homogenizer/generator could be utilized without the baffle system.



Figure 3-1: Polytron PT 6100 (Polytron PT 6100, 2010)



Figure 3-2: Brinkmann standard generator for maximum aeration (Brinkmann Instruments, 2004)

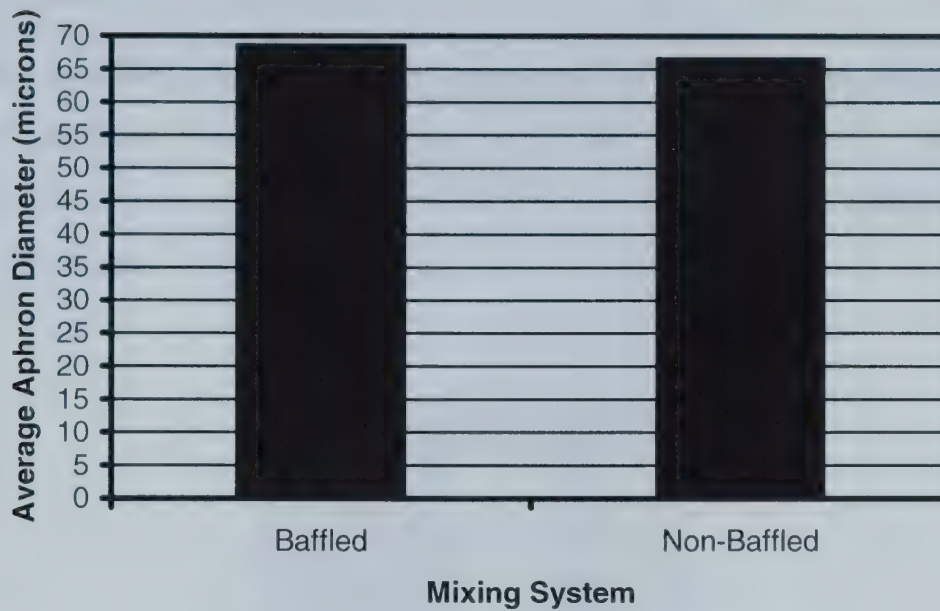


Figure 3-3: Comparison between initial bubble sizes generated with baffled and non-baffled mixers.

3.1.2 Equipment Used for CGA Characterization

3.1.2.1 Density

The density of the fluid was measured using a mud balance as shown in Figure 3-4. In the case where the density was low, a digital scale and fixed fluid volume was used.



Figure 3-4: Mud Balance (Group of Technology and Petroleum Engineering, 2009)

3.1.2.2 Viscosity

The shear viscosity of the fluid was measured by using the Brookfield DV II Digital Cone/Plate Viscometer similar to the one in Figure 3-5. The plastic viscosity, yield point and apparent viscosity was measured by using the Fann Viscometer (Figure 3-6).

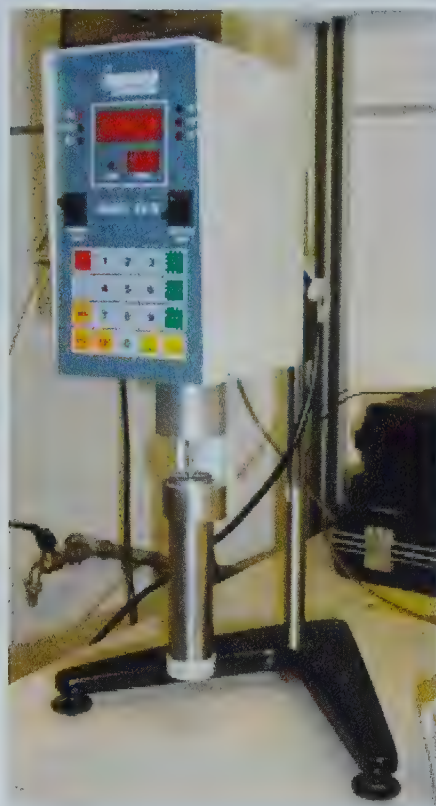


Figure 3-5: Brookfield DV II Digital Cone/Plate Viscometer (Universita di Parma, 2009)



Figure 3-6: Fann Viscometer (Group of Technology and Petroleum Engineering, 2009)

3.1.2.3 API Filtration

The API filtration loss test was performed by using a standard filter press.



Figure 3-7: API Filter Press (Obbye Integrated Services Ltd., 2009)

3.1.3 Materials Used for CGA Generation

The CGA fluid used in this study is composed of two main materials: a polymer and a surfactant.

The polymer utilized in this study is Xanthan Gum which was supplied by Bariod Industrial Drilling Products.

Two types of surfactants have been chosen for the generation of the CGA: Hexadecyltrimethyl ammonium bromide (HTAB), a cationic surfactant and Sodium dodecyl benzene sulfonate (DDBS), an anionic surfactant. These surfactants were chosen due to the past successes of previous researchers (Roy et al., 1992a; Roy et al., 1995b; Jackson et al., 1998)

3.2 EXPERIMENTAL PROCEDURE FOR CGA GENERATION AND CHARACTERIZATION

A two step procedure was followed to generate the CGA fluid: generation of the base fluid and generation of the CGAs

3.2.1 Experimental Procedure the Base Fluid Generation

Before the aphronized fluid can be created, a base fluid must be generated that can represent drilling fluid. Xanthan Gum (XG) – water mixture was used as the base fluid and it was chosen because of its viscous properties. The base fluid was generated by slowly adding the appropriate amount of XG in water for 16 minutes; 1 minute on low speed and 15 minutes at maximum speed.

3.2.2 Experimental Procedure the CGA Generation

Once the base fluid was prepared, it was allowed to cool down to room temperature, between 68 and 75 °F (20 – 24 °C). This was done to avoid destabilization of the CGAs at high temperatures. The CGA system is expected to

begin destabilization at temperatures above 40°C (104°F) and the CGAs will be completely destroyed when temperatures reach 65°C (149°F) (Longe, 1989).

Surfactant (either DDBS or HTAB) was added to the base fluid and it was mixed with either the Brinkmann Homogenizer Model PT 45/80 or the Polytron PT 6100 Generator. The base fluid and surfactant mixture was homogenized for 30 seconds at a speed of 5000 rpm unless otherwise stated.

3.2.3 *Density*

The standard API procedure was used to measure density with the mud balance. In the case where the density of the fluid was lower than the mud balance scale allowed a different procedure was performed. An empty graduated cylinder was weighed with a digital scale. The CGA fluid was then placed into that graduated cylinder up to a known volume. The graduated cylinder and CGA fluid was then weighed with a digital scale. The difference between the weight of the cylinder and CGA fluid and the weight of the cylinder was used to determine the weight of the CGA fluid. Since the volume of the CGA fluid in the cylinder was also known, the density of the fluid could be obtained from dividing the weight by the volume of the CGA fluid.

3.2.4 *Viscosity*

The standard procedures were used to measure shear viscosity, plastic viscosity, yield point and apparent viscosity.

3.2.5 *API Fluid Loss*

The standard API procedure was used to measure the API fluid loss.

3.3 PHYSICOCHEMICAL PROPERTIES OF CGA DRILLING FLUIDS

Experiments have been conducted to investigate factors affecting the physicochemical properties (ie viscosity, density, API filtration loss) of CGA

drilling fluids. Among the factors investigated are surfactant type and concentration, polymer concentration, spinning speed, mixing time and water quality.

3.3.1 Measurements of Viscosity, Density and API Filtration Loss

3.3.1.1 Density

As shown in Figure 3-8, as the amount of surfactant increases, the volume or number of the CGAs also increases. Naturally, as the volume of the air phase (CGA) increases, the density of the fluid will decrease. Density of the aphronized drilling fluid decreased from 6.3 ppg to 5.3 ppg as the surfactant concentration increased from 1 lb/bbl to 2 lb/bbl (Table 3-1). The aphronized fluid densities reported in this study were all measured under the atmospheric pressure condition. When it is circulated downhole, however, aphronized fluid will be exposed to pressures that are much higher than atmospheric pressure. Hence, the CGAs will compress and the density of the fluid will increase.

As the concentration of polymer (Xanthan Gum) increases for a fixed amount of surfactant, the density of the fluid also increases (Table 3-1). Essentially, with an increase in polymer (XG) concentration, the density of the liquid phase increases thus the density of the total fluid should increase.

The density of the CGA based fluid decreased as the mixing rate increased (Table 3-1), indicating that more CGAs were generated as the shear rate increased.

Results shown in Table 3-1 indicate that the length of the mixing time interval and the water quality have little effect on the density of the system.

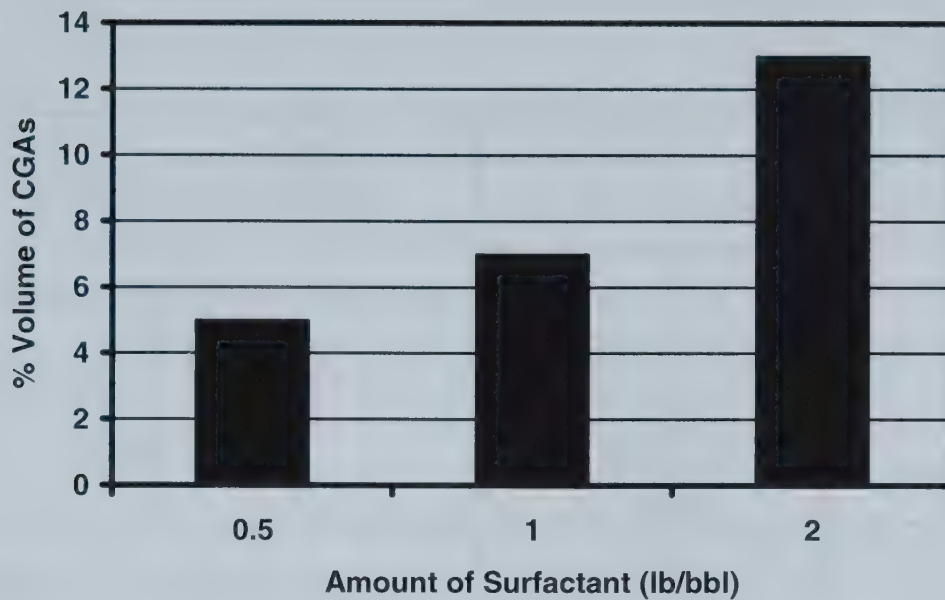


Figure 3-8: Effect of surfactant concentration on the % volume of CGAs in the aphronized drilling fluid.

The densities of aphronized drilling fluids prepared by using 1lb/bbl anionic (DDBS) and cationic (HTAB) concentrations were compared (Table 3-1). The density of anionic (DDBS)-based fluid (5.3 lb/gal) was found to be higher than the density of cationic (HTAB)-based fluid (4.6 lb/gal). This result indicates that either more CGAs can be generated by using cationic (HTAB) type surfactant or larger CGAs can be generated with the cationic (HTAB) type surfactant than that of anionic (DDBS) type surfactant.

Table 3-1: Summary of density results for CGA bubble factors.

		DENSITY (PPG)
SURFACTANT (DDBS) CONCENTRATION (LB/BBL)	0	8.4
	1	6.2
	2	5.3
POLYMER (XG) CONCENTRATION (LB/BBL)	1	5.1
	3	5.3
	5	6.6
SHEAR RATE	LOW	8.0
	MEDIUM	6.9
	HIGH	5.3
MIXING TIME (SEC/INTERVAL)	10	5.3
	20	5.3
	30	5.3
WATER TYPE	DE-IONIZED WATER	5.3
	TAP WATER	5.7
SURFACTANT TYPE	ANIONIC (DDBS)	6.2
	CATIONIC (HTAB)	4.5

3.3.1.2 Rheology

The effect of surfactant type and concentration on the rheology of the aphronized drilling fluids are shown in Figure 3-9 and Figure 3-10. Aphronized drilling fluids behave like yield pseudo-plastic type of fluids (Figure 3-9) with shear thinning characteristics (Figure 3-10). Anionic (DDBS) based fluids have a higher shear viscosity than that of cationic (HTAB) based fluids (Figure 3-9). Data shown in Figure 3-9 also illustrates that as the amount of surfactant increases, the apparent viscosity of the aphronized drilling fluid also increases.

The experimental results showing the effects of polymer and surfactant concentration, surfactant type, mixing (shear) rate, mixing time and water type on the plastic viscosity, yield point, apparent viscosity and low shear rate viscosity (LSRV) are summarized in Table 3-2 to Table 3-7.

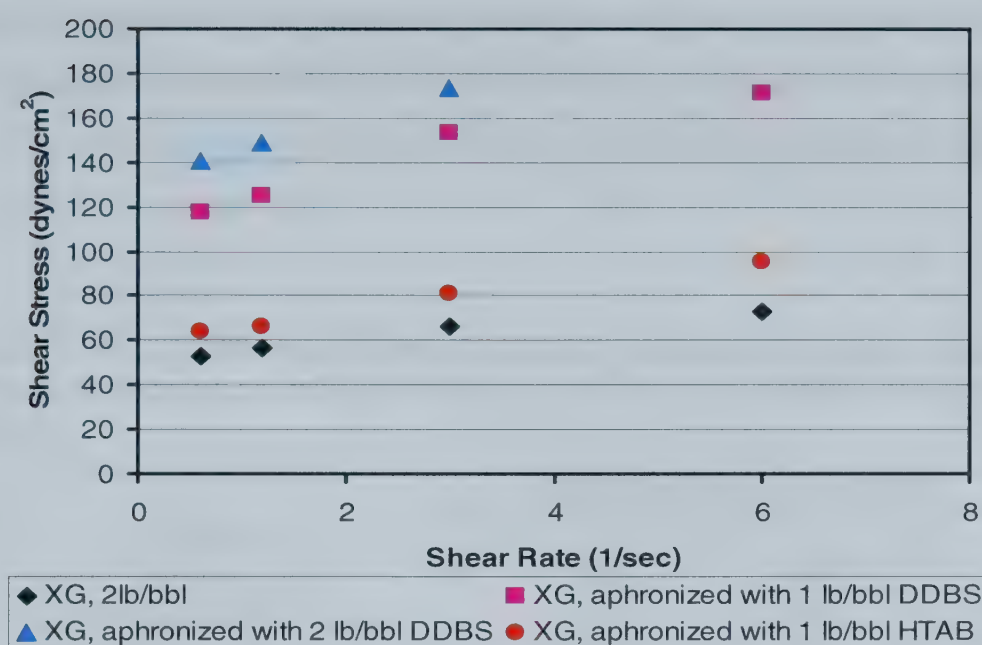


Figure 3-9: Effect of surfactant types and concentrations on the rheology of the aphronized drilling fluids.

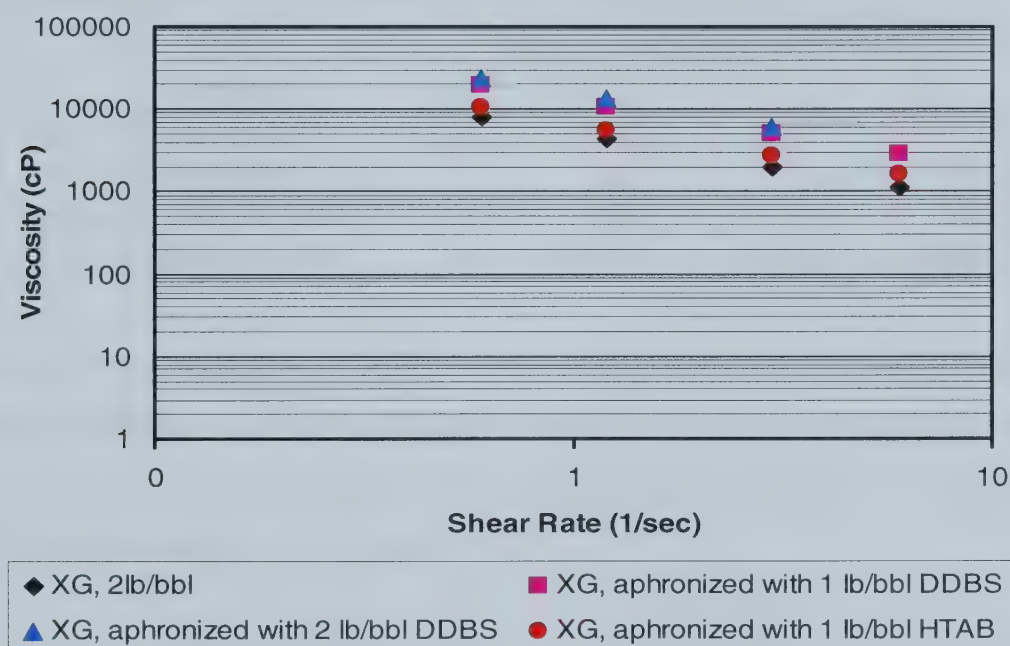


Figure 3-10: Effects of surfactant types and concentrations on the apparent viscosity of aphronized drilling fluids.

An increase in the anionic (DDBS) surfactant concentration (Table 3-2), and the Polymer (XG) concentration (Table 3-3) increases the plastic viscosity, yield point, apparent viscosity and LSRV. As the surfactant concentration increases,

the bubble population also increases, which in turn should increase the viscosity of the system. As the polymer (XG) concentration increases, the viscosity of the base fluid also increases, which will increase the overall viscosity of the system Table 3-3.

Table 3-2: Effect of anionic (DDBS) surfactant concentration on the physical properties of aphronized drilling fluid (prepared by using 3 lb/bbl XG base solution) .

Properties	Amount of Surfactant (lb/bbl)		
	0	1	2
Plastic Viscosity (cP)	12	15	19
Yield Point (lb/100 sq. ft.)	28	44	51
Apparent Viscosity(cP)	26	37	45
LSRV at 0.6 sec-1(cP)	7450	15967	22067

Table 3-3: Effect of polymer (XG) concentration on the physical properties of aphronized drilling fluid (prepared by using 2 lb/bbl DDBS)

Properties	Amount of Xanthan Gum(lb/bbl)		
	1	3	5
Plastic Viscosity (cP)	7	19	22
Yield Point (lb/100 sq. ft.)	20	51	85
Apparent Viscosity(cP)	17	45	64
LSRV at 0.6 sec-1(cP)	2767	22067	>31000

Increasing the mixing rate of aphronized drilling fluid also increases the plastic viscosity, apparent viscosity and LSRV (Table 3-4) indicating that more bubbles are created at higher mixing rates. The yield point, however, was not influenced much by the increasing mixing rate.

The data showing the effect of the mixing time interval and the type of water used for preparing the base fluid on the fluid properties are presented in Table 3-5 and Table 3-6, respectively. Results have shown that the mixing time length and the water type did not alter the aphronized drilling fluid properties significantly.

Table 3-4: Effect of shear rate on the physical properties of aphronized drilling fluid (prepared by using 2 lb/bbl DDBS surfactant and 3 lb/bbl XG).

Properties	Shear Rate		
	low	med.	high
Plastic Viscosity (cP)	10	17	19
Yield Point (lb/100 sq. ft.)	50	48	51
Apparent Viscosity(cP)	35	41	45
LSRV at 0.6 sec-1(cP)	18700	20233	22067

Table 3-5: Effect of mixing time on the physical properties of aphronized drilling fluid (prepared by using 2 lb/bbl DDBS surfactant and 3 lb/bbl XG).

Properties	Mixing Time (sec/interval)		
	10	20	30
Plastic Viscosity (cP)	19	18	17
Yield Point (lb/100 sq. ft.)	51	51	50
Apparent Viscosity(cP)	45	44	42
LSRV at 0.6 sec-1(cP)	22067	21467	21600

Table 3-6: Effect of water type on the physical properties of aphronized drilling fluid (prepared by using 2 lb/bbl DDBS surfactant and 3 lb/bbl XG).

Properties	Water Type	
	De-ionized Water	Tap Water
Plastic Viscosity (cP)	19	19
Yield Point (lb/100 sq. ft.)	51	58
Apparent Viscosity(cP)	45	49
LSRV at 0.6 sec-1(cP)	22067	21400

Experimental results showing the effects of surfactant type on the physical properties of drilling fluids are summarized in Table 3-7. Plastic viscosity of the cationic surfactant (HTAB)-based fluid (21 cP) was found to be higher than the anionic surfactant (DDBS)-based fluid (15 cP). The yield point of the cationic surfactant (HTAB)-based fluid (37 lb/100ft²), however, was lower than that of the anionic surfactant (DDBS)-based fluid (44 lb/100ft²). The apparent viscosity of a fluid reflects the combined effect of change in plastic viscosity and the yield point. The apparent viscosity of cationic surfactant (HTAB)-based fluid (39 cP) was found to be slightly higher than that of the anionic surfactant (DDBS)-based fluid (37 cP). There was a drastic difference between the LSRV of the cationic

surfactant (HTAB)-based fluid (1250 cP) and the anionic surfactant (DDBS)-based fluid (15967 cP). The low shear rate viscosity (LSRV) value strongly influences the solids transport capacity of the drilling fluids. Therefore, significant difference between the LSRV values implies that anionic surfactant (DDBS) based fluids might have better solids transport capacity than that of the cationic surfactant (HTAB) based fluids.

Table 3-7: Effect of surfactant type on the physical properties of aphronized drilling fluid (prepared by using 1 lb/bbl of surfactant and 3 lb/bbl XG).

Properties	Surfactant Type	
	DDBS	HTAB
Plastic Viscosity (cP)	15	21
Yield Point (lb/100 sq. ft.)	44	37
Apparent Viscosity(cP)	37	39
LSRV at 0.6 sec-1(cP)	15967	1250

3.3.1.3 API Filtration Loss

The filtration loss and spurt loss decreases with increasing surfactant concentration (Figure 3-11). Increasing surfactant concentration allows more microbubbles to be generated, which means more bubbles will be available to form a bridge in front of the pore structure and/or alternatively form an internal cake and hence, limit the filtration of fluid into the formation.

Figure 3-12 illustrates that both the filtration loss and the spurt loss decrease with increasing polymer (XG) concentration. This is expected since higher polymer (XG) concentrations yield higher fluid viscosity, which in turn, increases resistance of fluid to flow through porous media and, therefore, reduces fluid loss into the formation.

The fluid loss and spurt loss were not greatly affected by the mixing rate (Figure 3-13).

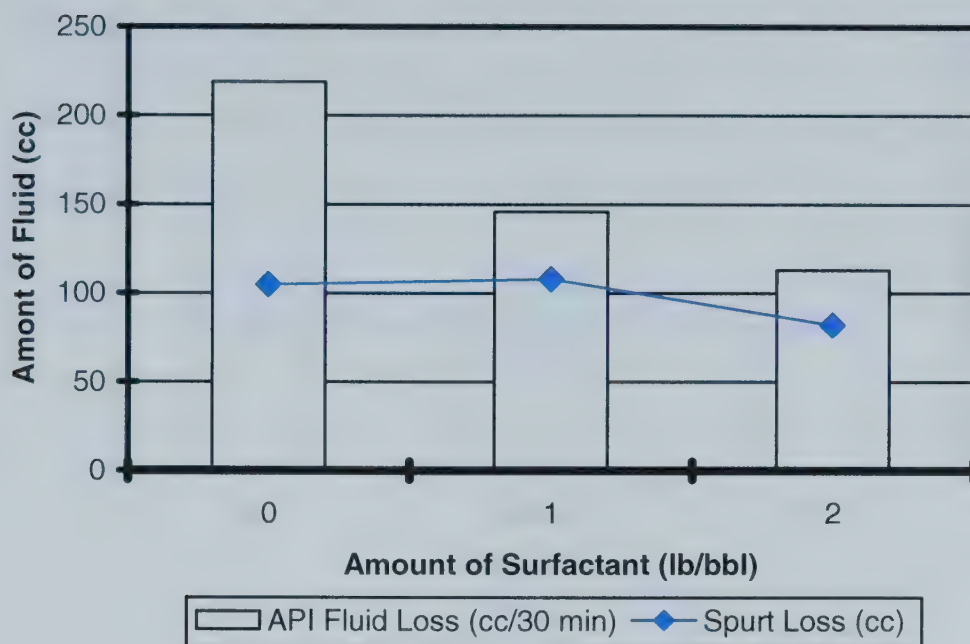


Figure 3-11: Effect of surfactant concentration on the API fluid loss and spurt loss with 3 lb/bbl XG.

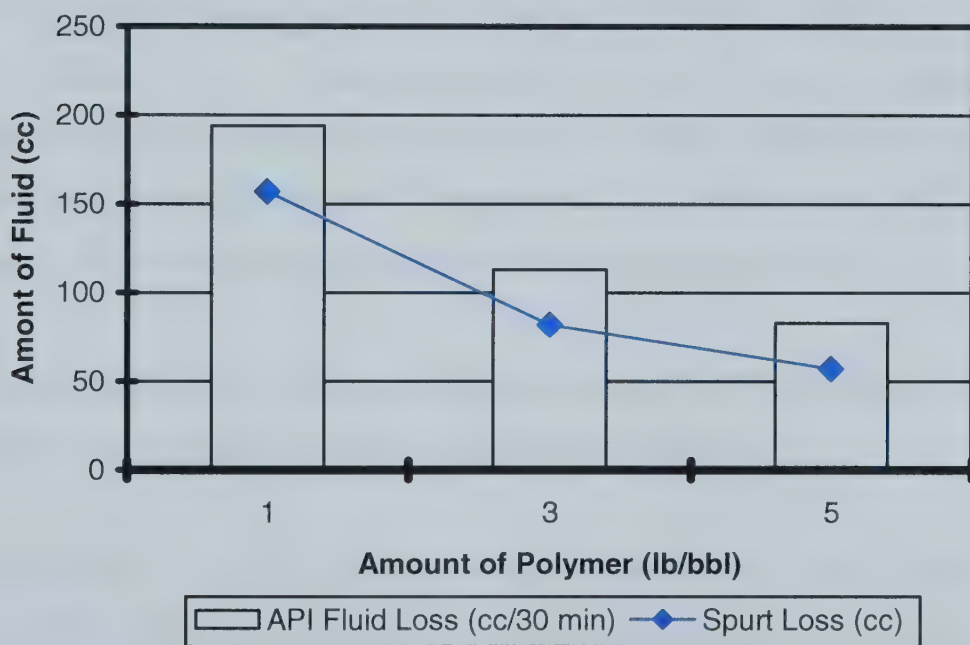


Figure 3-12: Effect of polymer (XG) concentration on the API fluid loss and spurt loss of 2lb/bbl DDBS.

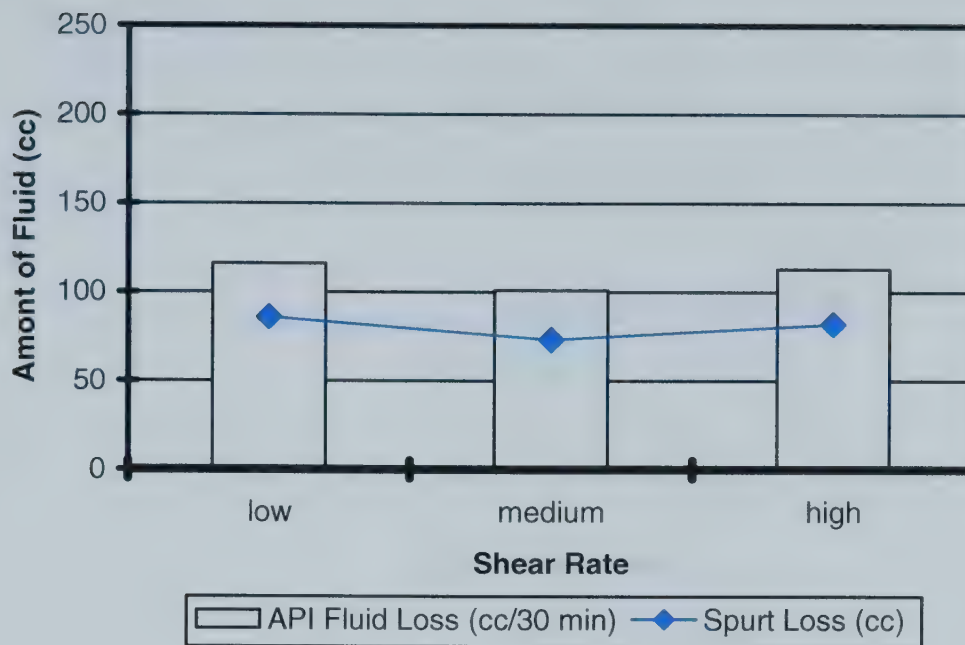


Figure 3-13: : Effect of shear rate on API fluid loss and spurt loss with 3 lb/bbl XG and 2 lb/bbl DDBS.

There was a slight increase in the fluid loss and spurt loss as the mixing time increased (Figure 3-14). Temperature rise is observed as the mixing time increased. Increasing temperature would reduce viscosity which in turn leads to more fluid loss into the formation. Temperature also affects the stability of the CGA (Longe, 1989) which can also have an effect on the fluid loss.

Type of the water used for preparing aphronized drilling fluid did not influence the filtration loss and spurt loss values significantly (Figure 3-15).

The filtration loss and the spurt loss were significantly lower for cationic surfactant (HTAB)-based fluids than that of the anionic surfactant (DDBS)-based fluids (Figure 3-16). However, some solid precipitates were observed when cationic surfactant (HTAB) was used with water-polymer (XG) solution to form the aphronized drilling fluid. Therefore, reduction in filtration loss in the case of cationic surfactant (HTAB)-based fluid can not be attributed solely to the presence of more microbubbles. Some of the reduction of filtration loss and spurt

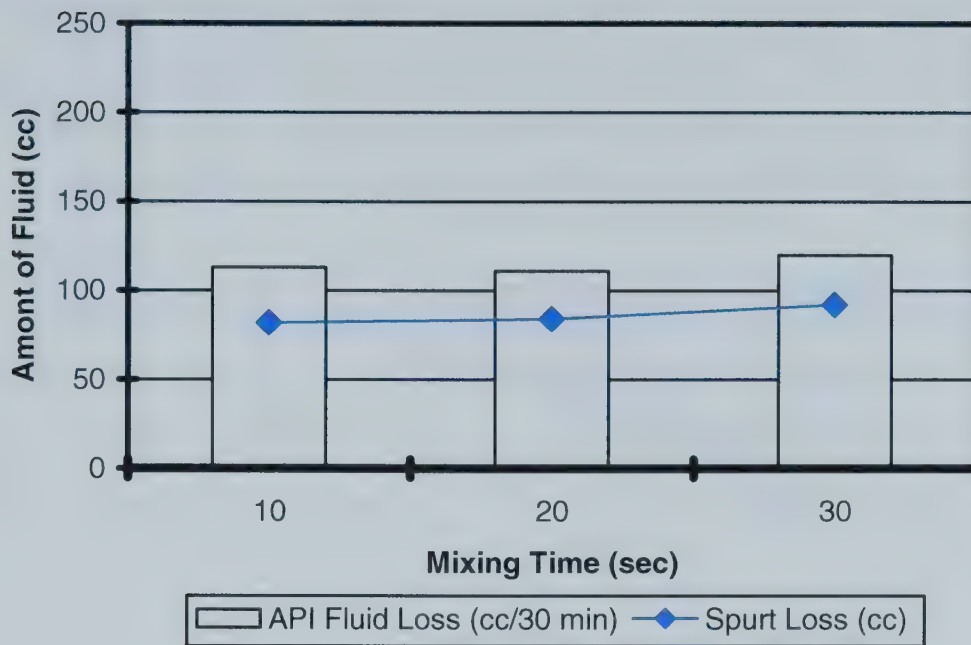


Figure 3-14: Effect of mixing time on API fluid loss and spurt loss with 3 lb/bbl XG and 2 lb/bbl DDBS.

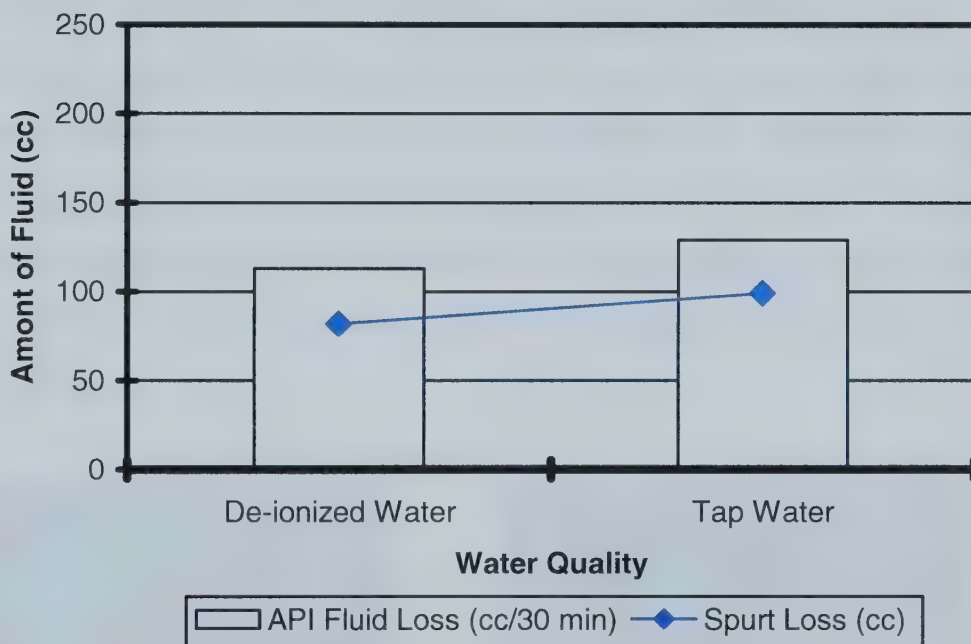


Figure 3-15: Effect of water type on API fluid loss and spurt loss with 3 lb/bbl XG and 2 lb/bbl DDBS.

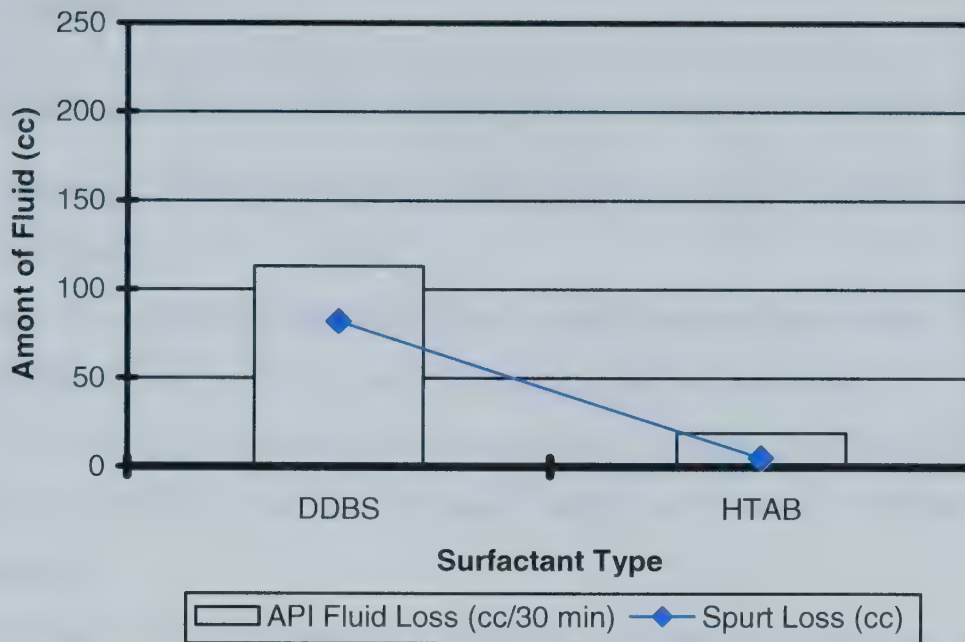


Figure 3-16: Effect of surfactant type on API fluid loss and spurt loss with 3 lb/bbl XG and 2 lb/bbl DDBS.

loss was most likely due to the presence of this precipitate instead of CGA blockage. Microscopic pictures of aphrons generated by using anionic (DDBS) and cationic (HTAB) surfactants are shown in Figure 3-17. Formation of a white long-hair like precipitate was observed in the cationic surfactant (HTAB) based aphronized fluid (Figure 3-17b), indicating a possible chemical reaction between cationic (HTAB) surfactant and the base-fluid prepared by mixing water and polymer (XG).

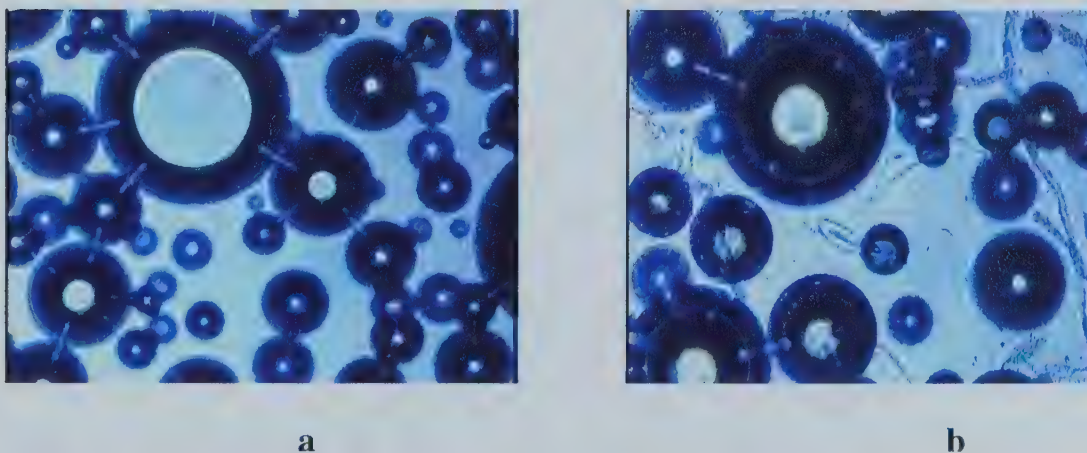


Figure 3-17: Comparison between microscopic pictures of CGAs made with a) DDBS and b) HTAB.

3.4 SUMMARY

As a result of the bulk fluid study, the following conclusions can be drawn

- The rheology of the aphronized drilling fluids can be classified as yield pseudo plastic.
- Overall, the addition of the CGA to the system increased the viscosity and the API filtration loss and decreased the density of the drilling fluid.
- As the polymer concentration increased, the viscosity and density of the aphronized drilling fluid also increased while the volume of filtration loss decreased.
- An increase in the surfactant concentration decreased the filtration loss and increased the viscosity of the aphronized drilling fluid.
- Type of water did not influence the physical properties of the aphronized drilling fluids. Since the water quality showed little effect on all parameters, tap water can readily be used for preparing the base fluid.
- Aphronized drilling fluids generated by using cationic surfactants had lower filtration volumes as compared to fluids generated by using anionic surfactants but this may be due to the presence of precipitates and not the CGA alone.
- For a fixed base fluid volume, more CGAs were generated at higher surfactant concentrations.

4 INVESTIGATION OF THE FACTORS CONTROLLING COLLOIDAL GAS APHRON STABILITY

The stability of the CGA is affected by the viscosity of the fluid as well as by the amount of surfactant used to generate the CGAs. The stability experiments have been conducted to determine the amount of polymer and surfactant needed to maintain an acceptable stability. The following bulk CGA fluid analyses was conducted as part of the stability investigation: 1) Critical Micellar Concentration (CMC) of the system, 2) Rheological characterization of CGA based drilling fluids with time and 3) Stability analyses through drainage rate measurements with time and temperature.

4.1 APPARATUSES AND MATERIALS USED FOR THE STUDY OF CGA STABILITY

4.1.1 *Equipment Used for the Critical Micellar Concentration (CMC) Examination*

The Du Nouy ring method (PHYWE, 2010) and the calibrated Fisher Surface Tensiomat Model 21 similar to the one given in Figure 4-1 was used to determine the critical micellar concentration of the CGA system.



Figure 4-1: Fisher Surface Tensiomat Model 21 (Fisher Scientific, 2009)

4.1.2 Equipment Used for the Change in Rheology with Time

A 12 speed Fann model 35A viscometer was used to determine the change in shear stress vs. shear rate relationship with time for various compositions of aphronized fluid. This equipment has been described in Section 3.1.2.2.

4.1.3 Equipment Used for the for Drainage Measurements

The change in bulk fluid volume with pressure and temperature was measured using the Schlumberger PVT Cell (100 cc, 15 ksi, H₂S). Figure 4-2 is an image of the PVT device.



Figure 4-2: Image of the PVT apparatus.

4.1.4 *Materials Used for CGA Stability*

The CGA fluid was composed of a polymer (Xanthan Gum) and an anionic surfactant (DDBS). Concentrations of polymer base fluid range from 0 to 2 lb/bbl. Concentrations of DDBS were used in this study range from 0.035 lb/bbl (100 ppm) to 1lb/bbl. The 0.035 lb/bbl concentration is below the critical micellar concentration (CMC), meaning that the surfactant is unable to make micelles in the fluid. The 1 lb/bbl concentration is above the CMC.

4.2 EXPERIMENTAL PROCEDURES FOR THE STUDY OF CGA STABILITY

4.2.1 *Experimental Procedure for the Critical Micellar Concentration (CMC) Examination*

Surface tension experiments were conducted to determine the minimum amount of surfactant need to form stable CGAs. The concentration of the surfactant was varied from 0 to 600 ppm for the anionic surfactant (DDBS) and from 0 to 550 ppm for the cationic surfactant (HTAB). Both deionized water and City of Edmonton tap water were used for the initial test. The surfactant was added to a known amount of water to make up the concentration. The solution was then stirred for 1 minute using a magnetic stirrer. Following the stirring, the surface tension was measured using the standard deNouy ring method and the calibrated Fisher Surface Tensiomat Model 21. The weight and volume of each sample was also recorded.

4.2.2 *Experimental Procedure for the Change in Rheology with Time*

The standard API procedure was used to measure the shear stress of the fluid with the Fann Viscometer. In order to obtain the shear stress with time, the fluid was allow to sit in a static state in the Fann Viscometer cup for 30 minute intervals after which, the shear stress of the fluid was measured. Time intervals of 0, 30, 60, and 120 minutes after the fluid was aphronized were recorded.

4.2.3 Experimental Procedure for the for Drainage Measurements

The experimental procedure for the drainage measurements can be divided into two categories: 1) Drainage rate with time under atmospheric pressure and room temperature and 2) Bulk density under elevated pressure and temperature.

4.2.3.1 Experimental Procedure for Drainage Rate with Time

In these experiments, the creaming rate of the CGAs is determined. Creaming is the phenomena of the bubbles separating themselves from the aqueous solution. Under static condition, there will be an interface between the separated (aqueous solution) and the non-separated portion (existing CGAs). The height of the water/CGA interface and the surface/CGA interface will be measured as a function of time. As the time passes, the height of the interface between atmosphere and the bubbles will decrease due to CGA bubble breakage. The stability is inversely proportional to the rate of creaming.

Figure 4-3 illustrates the drainage process for foams. A 250 ml graduated cylinder was used for this study. Figure 4-3a represents the height of the fluid before mixing or generation of CGA's. Figure 4-3b shows the initial height of the

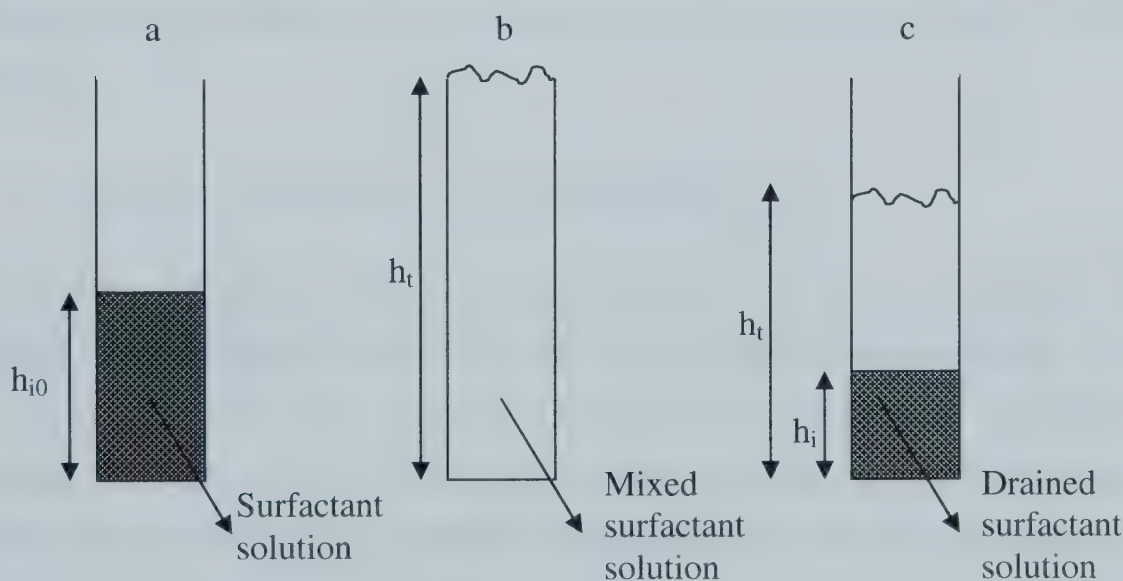


Figure 4-3: Drainage process for CGA dispersion (After Jauregi et al., 2000).

aphronized fluid in the graduated cylinder. The height of the fluid is recorded as (h_t). With time, the total height (h_t) of the solution will decrease. As well, the base fluid will drain out of the foams laminar region and will accumulate at the bottom of the cylinder (Figure 4-3c). The height of the drained base fluid (h_i) as well as the total height (h_t) are recorded with time.

4.2.3.2 Experimental Procedure for Bulk Density under Elevated Pressure and Temperature

The Schlumberger PVT Cell (100 cc, 15 ksi, H_2S) was used for these experiments. The fluid was inserted into the PVT cell via the accumulator and pump. The image of the fluid inside the PVT cell was transmitted to the computer via a camera. The camera is equipped with cross hairs. The cross-hairs were lined up to the height of the fluid in the cell. The cross-hair value (ie. height) was then zeroed. The pressure of the cell was then increased at intervals of 50 psi (344.7 kPa) from 0 to 500 psig (3447 kPa) at a fixed temperature. The cross-hairs were re-aligned with the height of the fluid at each pressure interval. From this, the change in volume of the fluid with pressure can be calculated using correlations provided by Schlumberger for this particular piece of equipment. The density of the fluid was then estimated using the change in volume of the fluid and the known density at atmospheric conditions. Experiments were conducted in this manner with the temperature of the cell set to 25, 50, 75 and 100°C.

4.3 CRITICAL MICELLAR CONCENTRATION

Figure 4-4 and Figure 4-5 show the experimental results. From the figures it is evident that the surface tension decreases initially then becomes constant. The transition point is the point where the Critical Micellar Concentration (CMC) is reached. In Figure 4-4, the CMC of the anionic surfactant (DDBS) is reached around 450 to 500 ppm for deionized water and in Figure 4-5, the CMC of the

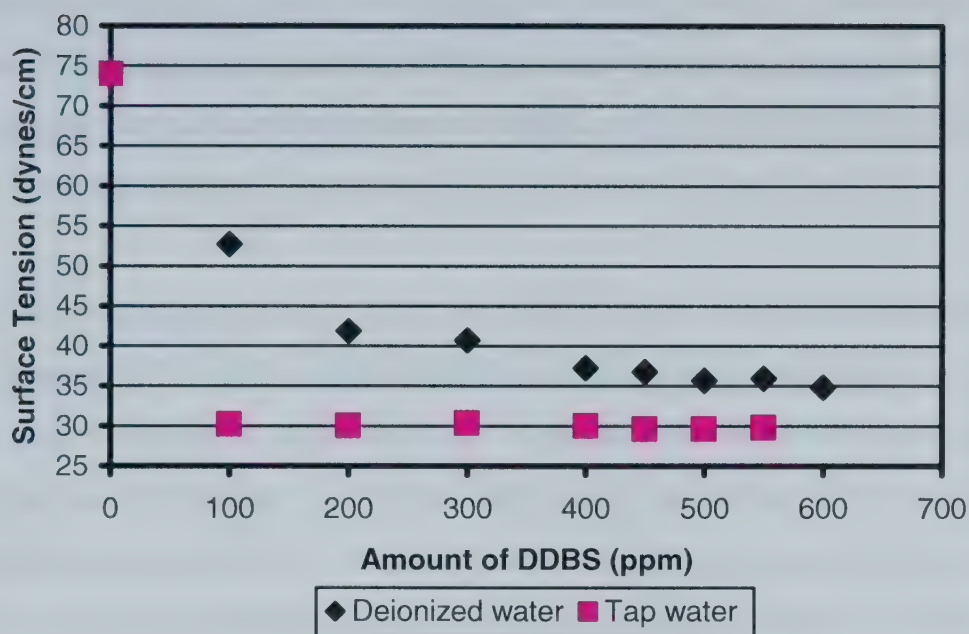


Figure 4-4: Surface tension of anionic surfactant (DDBS) solutions in deionized and tap water.

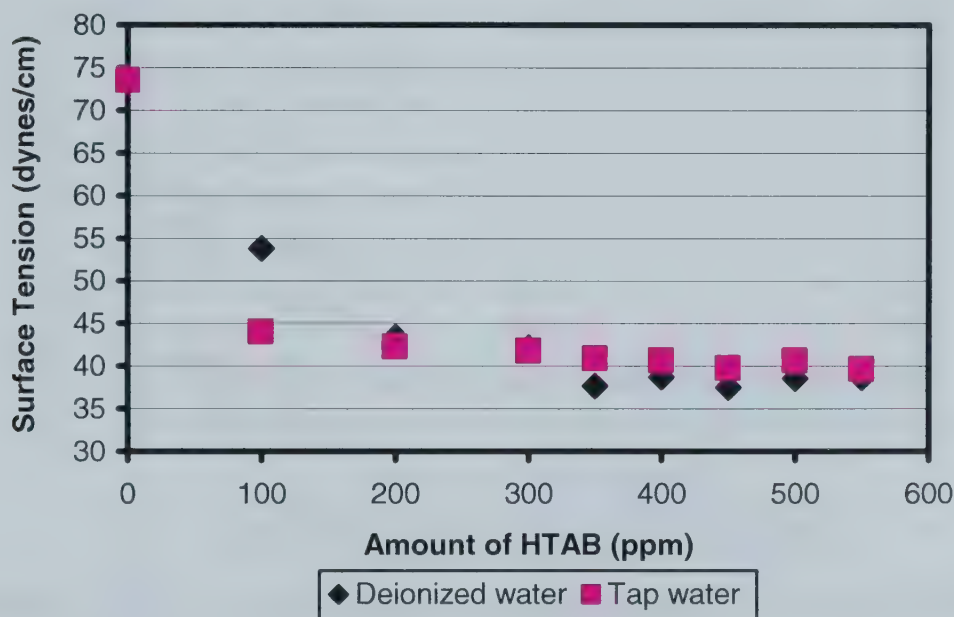


Figure 4-5: Surface tension of cationic surfactant (HTAB) solutions in deionized and tap water.

cationic surfactant (HTAB) is reached around the 350 ppm mark for deionized water. This is consistent with previously reported values (Roy et al., 1992a). In the cases with the tap water, the surface tension becomes constant at a very early stage. At 50 ppm for the DDBS case, the surface tension is very similar to that of

the 500 ppm reading. This is most likely due to the presents of electrolytes in the tap water. Electrolytes lower the CMC of ionic surfactant (Longe, 1989). This will decrease the surface tension more rapidly and can also decrease the size of the microbubble formed.

The CMC experiments were also conducted with various concentrations of xanthan gum (XG). XG was generated using tap water. Figure 4-6 shows the results and it is evident that the CMC is reached between 100 and 1000 ppm depending on the amount of XG utilized where the higher CMC is found for higher concentrations of XG. This indicates that with an increase in the viscosity of the system, the surfactant molecules are less able to find the surface of the fluid.

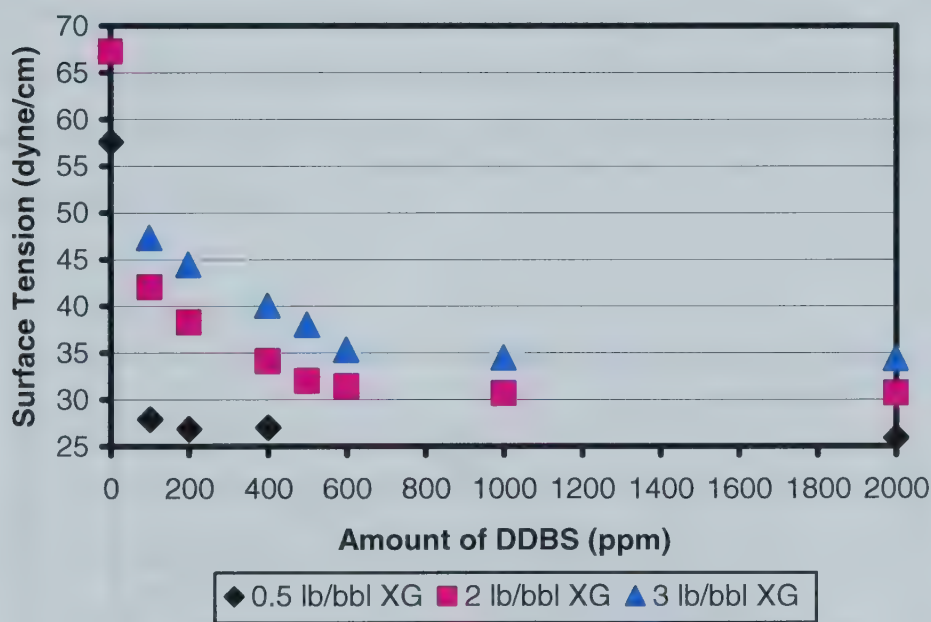


Figure 4-6: Surface tension of anionic surfactant (DDBS) solutions with various polymer (XG) concentrations.

4.4 CHANGE IN RHEOLOGY OF CGA DRILLING FLUID WITH TIME

The shear stress vs. shear rate diagrams of different CGA based drilling fluid compositions were generated at 30 minute time intervals. Figure 4-7 shows that for the fluid prepared by using 2lb/bbl XG and 1 lb/bbl DDBS, the viscosity did not change over a 120 minute interval.

Figure 4-8 illustrates the results for the fluid formulated by using 2 lb/bbl XG and 0.035 lb/bbl DDBS. Similar to the case shown in Figure 4-7, the shear stress vs. shear rate behavior did not change significantly over the time interval of 120 minutes.

Reduction of surfactant concentration from 1 lb/bbl to 0.035 lb/bbl did not have any impact on how rheological behavior changed with time. Despite the fact that surfactant concentration was reduced, fluids retained their effective viscosity during the 120 minute period.

Experimental results for the fluid formulated by using 0.5 lb/bbl XG and 1 lb/bbl DDBS are shown in Figure 4-9. Over time, higher shear stress values were measured at the same shear rates (i.e. apparent viscosity increased). A change in shear stress with time is an indication that the fluid is unstable and the phases (ie CGA and base fluids) may be separating. This instability will cause varied results in the shear stress with time.

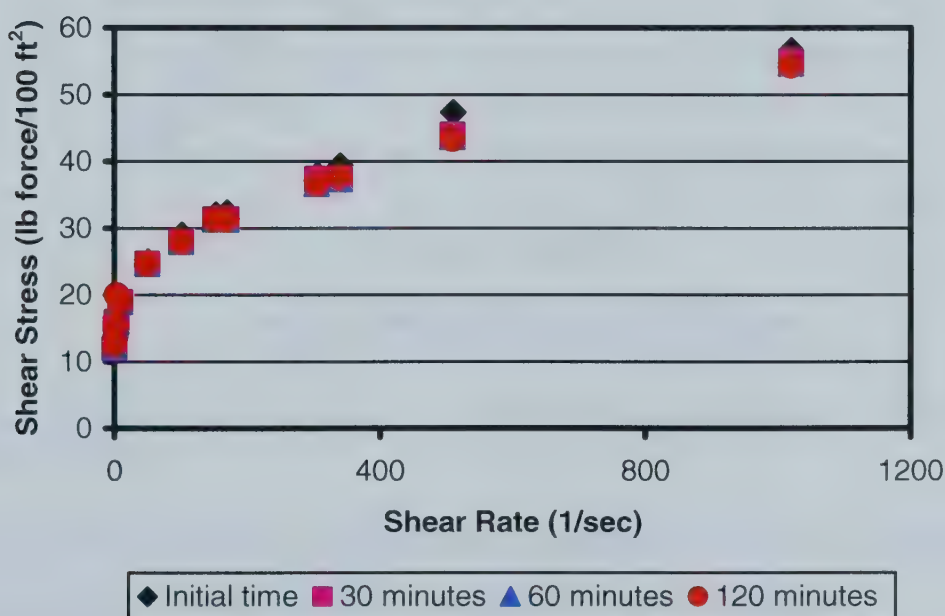


Figure 4-7: Shear stress vs. shear rate at different time intervals for 2lb/bbl XG and 1lb/bbl DDBS.

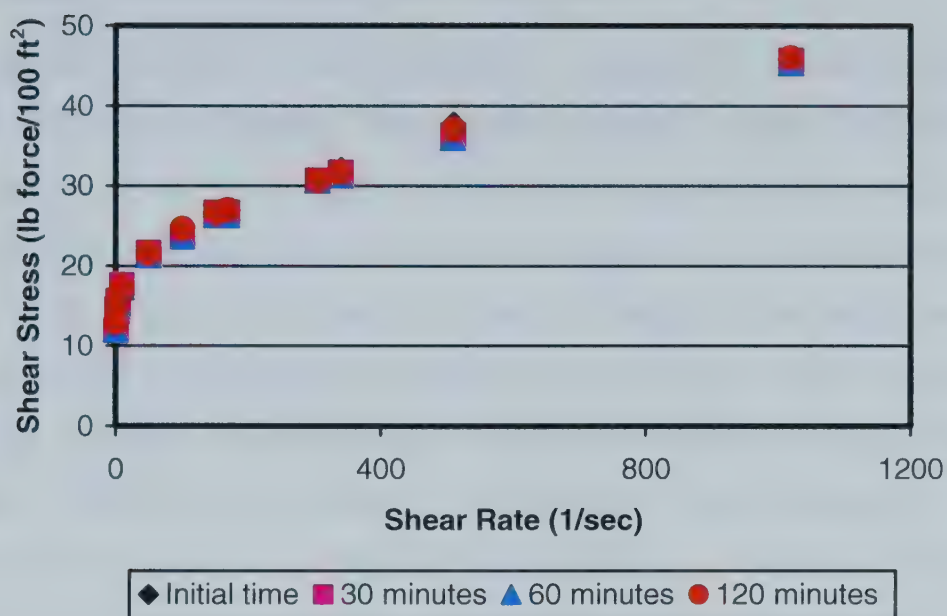


Figure 4-8: Shear stress vs. shear rate at different time intervals for 2lb/bbl XG and 0.035 lb/bbl DDBS.

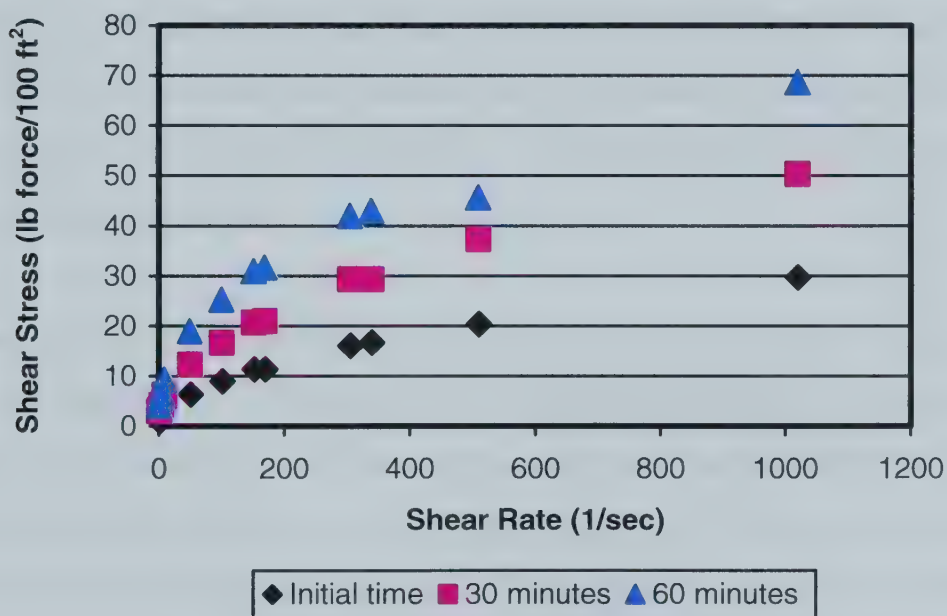


Figure 4-9: Shear stress vs. shear rate at different time intervals for 0.5lb/bbl XG and 1 lb/bbl DDBS.

Results from these analyses indicated that the viscosity of the base fluid controls the time dependent change of CGA based drilling fluids' rheology.

4.4.1 Drainage Rate (Creaming) Measurements

The drainage experiments were conducted to determine the homogeneity with time of CGA based drilling fluids with different polymer and surfactant concentrations. Both the change in the interface height (h_i in Figure 4-3) and the change in the total height of the solution (h_t in Figure 4-3) is an indication of the stability of the fluid. The change in interface height is an indication of the separation of the foam from the base fluid. Once the base fluid drains from the foam fluid, the foam fluid becomes dry and is more prone to coalescence and breakage. The change total height is an indication of the coalescence. Figure 4-10 shows the change in the height of the interface as a function of a change in polymer (XG) concentration. The height of the interface reached a constant value for 0.5 lb/bbl XG within 20 minutes. In contrast, when the polymer (XG) concentration is 1lb/bbl, the interface did not reach a constant state before 240 minutes. This indicates that drainage is slowed with higher polymer concentration. Figure 4-11 shows the total height of the solution decreased at a slower rate with increasing XG concentration. Increasing viscosity of the base solution increased the stability of the CGA. Similar results were also reported by Save and Pangarkar (1994).

The change in interface height (h_i) as a function of surfactant concentration is shown in a Figure 4-12. The height of the interface (h_i) reached a constant value at similar times for all three surfactant concentrations but the height of the liquid drained was greater at lower surfactant concentrations. This is because at lower surfactant concentrations, there are less CGAs generated. Less CGAs means that there is less gas in the total volume of the fluid. For each experiment, the initial volume of foam was fixed (250 ml). Therefore because there is less gas in the volume (250 ml) with lower surfactant concentrations, there will be more liquid in that volume and thus the total height of the liquid foam interface will be greater for lower surfactant concentrations. The change in the total height (h_t) with surfactant concentration is given in Figure 4-13. It shows that the total height for each experiment was similar with the lower surfactant concentration maintaining

a greater height at the later stages of the experiment. This is also due to the volume of liquid in the foam. With a greater liquid volume and less gas volume, the total height of the foam column will be greater due to the liquid volume.

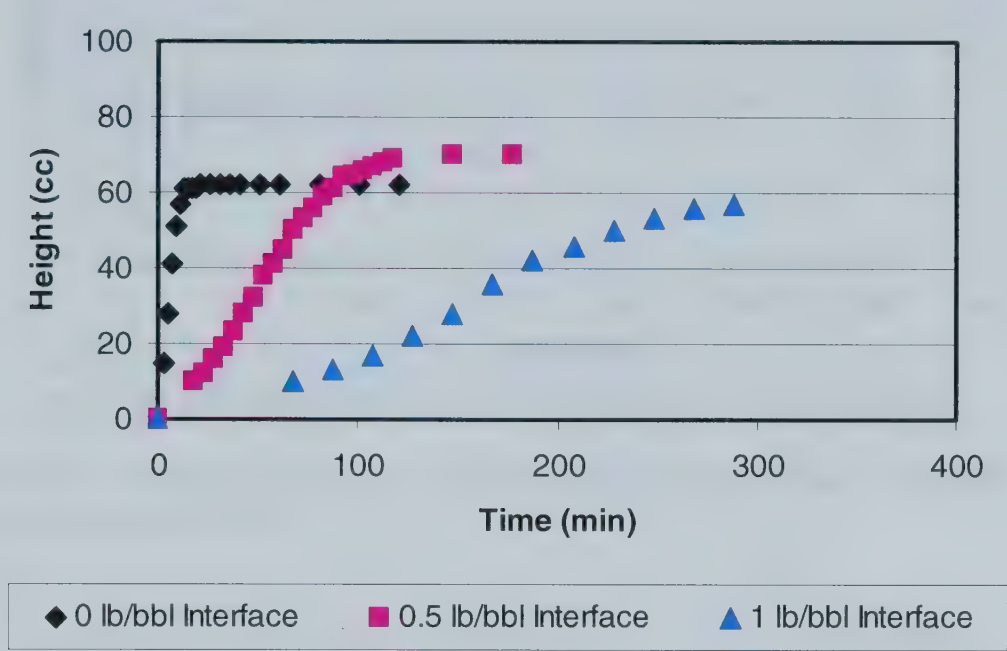


Figure 4-10: Change in foam/polymer interface (h_i) with a change in polymer (XG) concentration with 1 lb/bbl DDBS.

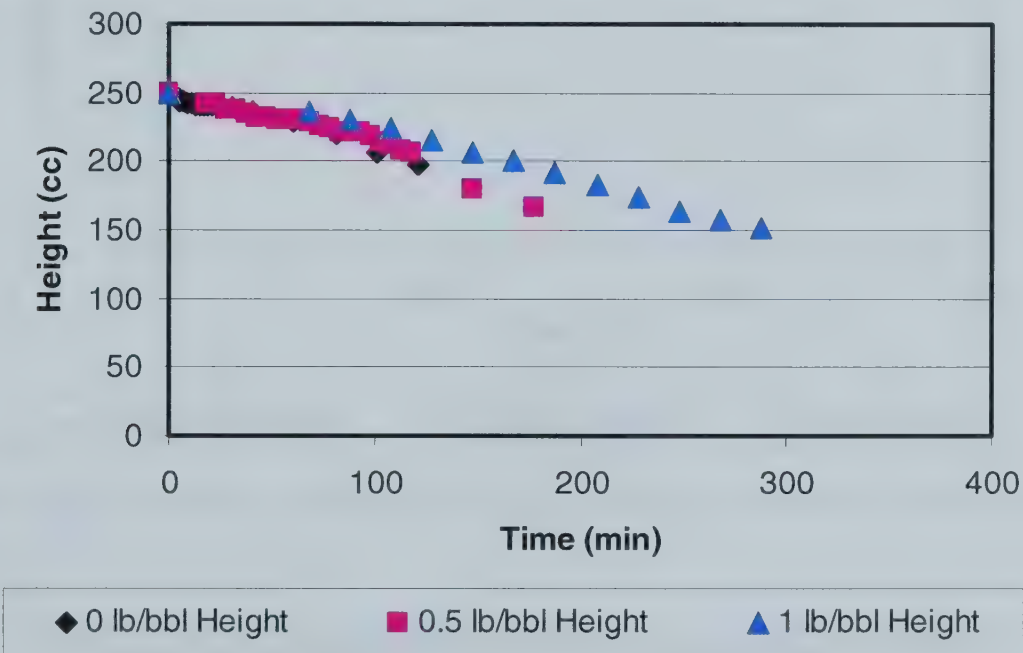


Figure 4-11: Change in total foam height (h_t) with a change in polymer (XG) concentration with 1 lb/bbl DDBS.

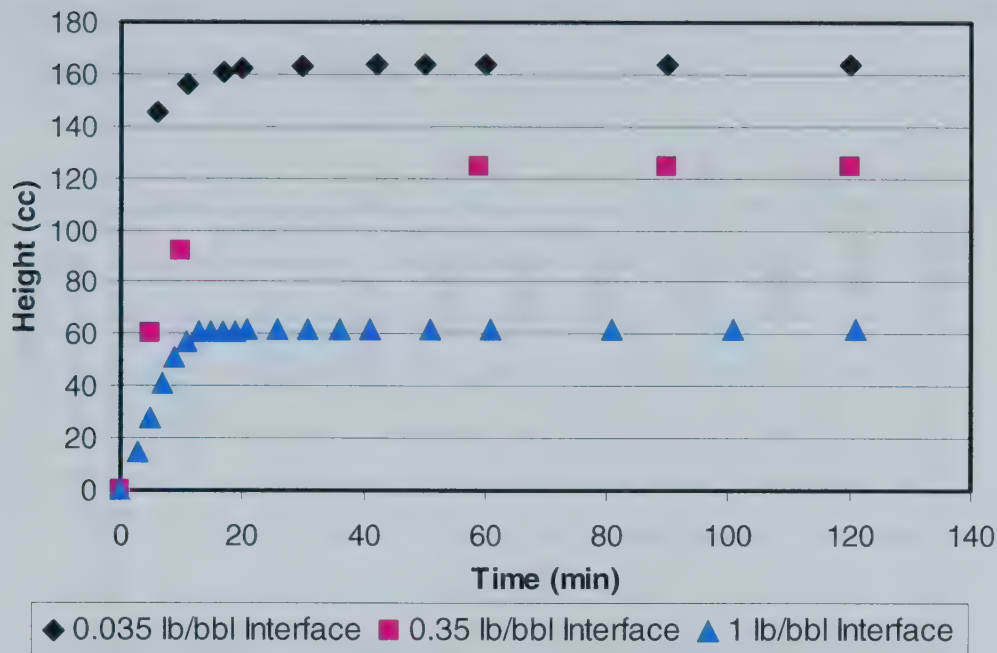


Figure 4-12: Change in foam/polymer interface (h_i) with a change in DDBS concentration with no XG.

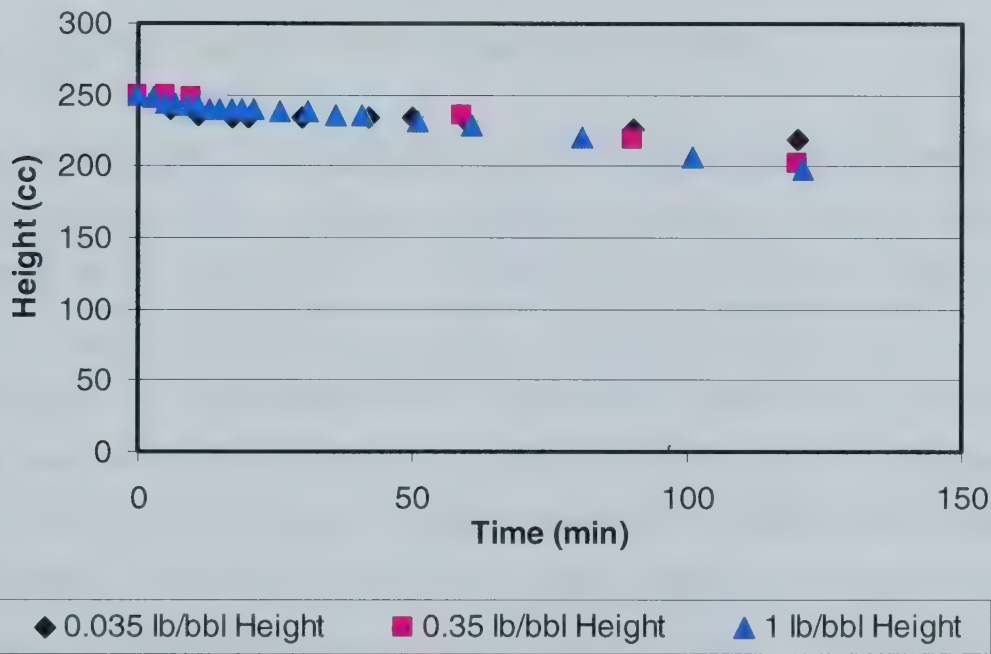


Figure 4-13: Change in total height (h_t) with a change in DDBS concentration with no XG.

4.4.2 Bulk CGA Fluid Characterization with Pressure and Temperature

The change in density of the bulk CGA fluid with pressure and temperature is presented in Figure 4-14. The concentration of polymer and surfactant used for this study is 2 lb/bbl and 1 lb/bbl respectively. It is evident that as the pressure

increases, the density of the fluid also increases. As well, with an increase in temperature, the density decreases.

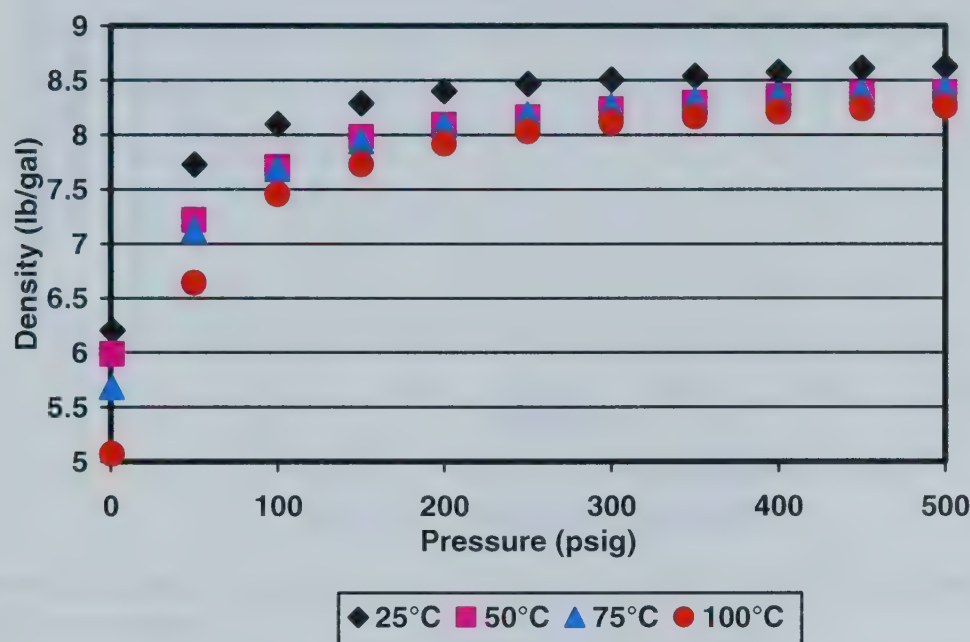


Figure 4-14: PVT data for 2 lb/bbl XG and 1 lb/bbl DDBS.

An experiment was also conducted to determine the change in foam/polymer interface (h_i from Figure 4-3) due to temperature increases. Figure 4-15 illustrates the change in the interface due to temperature. The data obtained from the PVT cell is compared to the previously presented (Section 4.4.1) drainage measurements at room temperature. Since the volume used for the high temperature measurements differs from that used in Section 4.4.1, the height of the interface (h_i) was converted to relative density of the foam phase by using the initial density and height to get the fixed total weight and using the weight to calculate a new relative density from the change in height. The change in height (h_i) quoted is actually a change in volume in ml. This relative density value indicates the density of the fluid that still exists as foam. As time passes, the denser base solution drains from the foam phase and the density of the foam phase decreases. From the figure, it is evident that increasing the temperature of the foam, decreases the density of the foam phase at a faster rate thus the fluids stability is decreased with and increase in temperature.

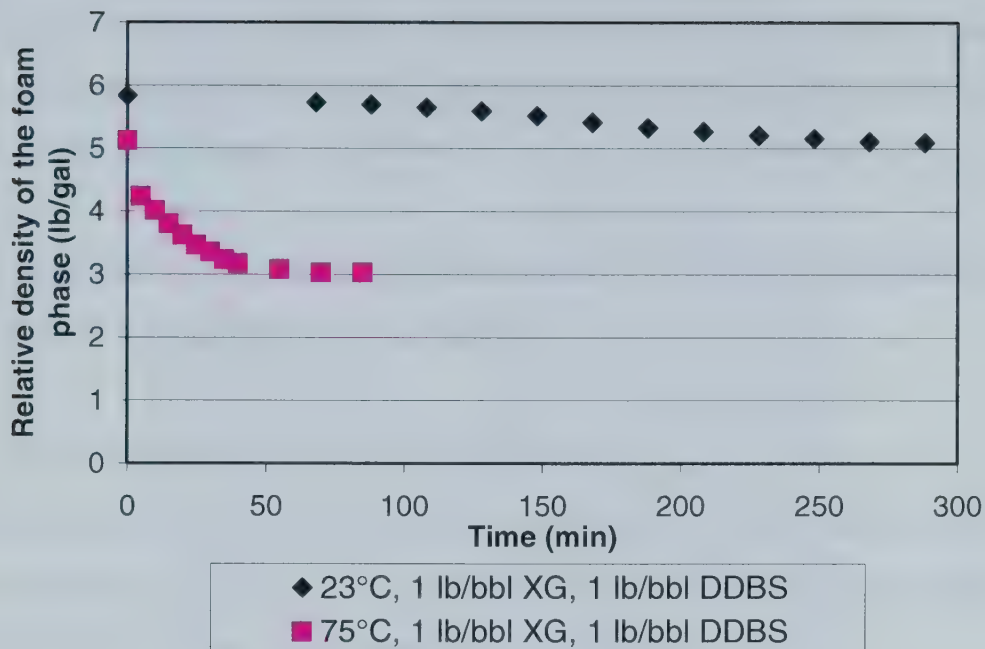


Figure 4-15: Change in drainage with a change in polymer (XG) concentration at differing temperatures.

4.5 SUMMARY

As a result of the bulk fluid study, the following conclusions can be drawn

- Viscosity of the base fluid strongly influenced the stability of the fluid with time. Higher base fluid viscosity led to more stable micro-bubbles.
- As pressure increased and temperature decreased, the density of the fluid increased.
- Temperature increased the drainage rate of the CGA fluid and in turn decreased the stability of the fluid.

5 CGA BUBBLE SIZE CHARACTERIZATION

Sizing of the CGA bubble is very important as it is one of the main factors that influence formation pore blockage. The factors that influence the size of the CGA bubble are examined here.

5.1 EQUIPMENT AND MATERIALS USED FOR THE DETERMINATION OF THE CGA BUBBLE DIAMETER

5.1.1 *Measurement of the CGA Bubble Diameter*

A Zeiss microscope (13X magnification) and a CCD camera were used to take images of the CGA bubbles. The diameter of the CGA bubble in the images was measured using a screen caliper as shown in Figure 5-1.

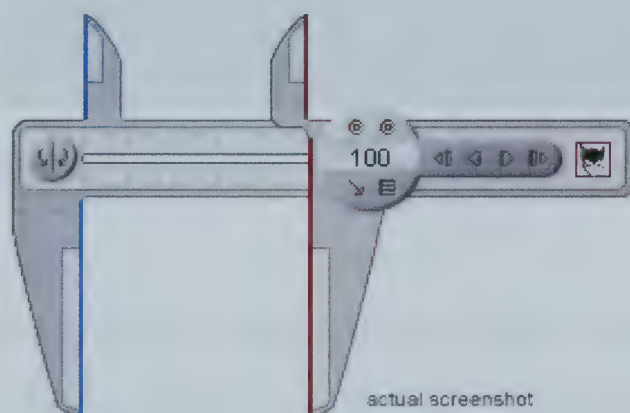


Figure 5-1: Screen Caliper (Iconico, 2009)

5.1.2 *Measurement of the CGA Bubble Diameter under Elevated Pressure*

High pressure experiments were performed by pressurizing a Jerguson cell (4000 psi maximum pressure) with a view window and obtaining digital images of the fluid in the cell. Figure 5-2 shows the Jerguson cell and the stereomicroscope used for the experiment. An Isco LC-5000 Syringe pump was connected to the Jerguson cell and the cell was placed under the stereomicroscope. The screen caliper (Figure 5-1) was used to measure the CGA diameter on the images.



Figure 5-2: Jerguson Cell and stereoscope used for pressurized experiments.

5.1.3 Measurement of the CGA Bubble Diameter under Elevated Temperature

A Napco E-Series Model 603 mechanical convection oven was used to heat the CGA fluid for the measurement of CGA bubble diameter at elevated temperatures. The screen caliper (Figure 5-1) was used to measure the CGA diameter on the images.

5.1.4 Materials Used for CGA Stability

The CGA fluid was composed of a polymer (Xanthan Gum) and an anionic surfactant (DDBS). Concentrations of polymer base fluid range from 0.5 to 5 lb/bbl. Concentrations of DDBS were used in this study range from 0.035 lb/bbl (100 ppm) to 2 lb/bbl.

5.2 EXPERIMENTAL PROCEDURE USED FOR THE DETERMINATION OF THE CGA BUBBLE DIAMETER

5.2.1 *Measurement of the CGA Bubble Diameter*

In order to determine the CGA bubble diameter, CGA fluid was transferred to a microscopic slide and pictures of the CGA bubbles were taken using a Zeiss microscope (13X magnification) and a CCD camera. Care was taken to ensure that the pictures were obtained immediately following the aphron generation process. The pictures were saved to a computer. The diameters of the aphrons in the pictures were then measured manually on the computer screen. Care was taken to ensure that each picture size was identical so that comparison could be made between all aphron diameters obtained. A screen caliper (Figure 5-1), which has a measurement increment of 1 pixel, was used to measure the diameter of the individual aphrons on the screen. A picture of a stage micrometer was also taken and saved to a computer. The size of this picture was also the same as the aphron pictures. The number of pixels corresponding to 1 mm distance on the micrometer picture was measured by using the same screen caliper. A scaling factor describing the number of pixels per mm of actual length could then be obtained. Finally, the aphron diameter measurements in pixels were converted into actual lengths in microns by using the pixel/unit length scaling factor. For the measurement of bubble size, one pixel is equal to 0.9 μm .

5.2.2 *Measurement of the CGA Bubble Diameter with Time*

In order to determine the CGA bubble diameter with time, a similar procedure to the one described in Section 5.2.1 was used. Pictures of the CGA bubbles on microscopic slide were taken using a Zeiss stereomicroscope (6.5X magnification) and a CCD camera at 30 minute intervals. In between the intervals, the lighting on the microscope was turned off to ensure that the CGA sample was not being heated. For the measurement of bubble size with time, one pixel is equal to 1.8 μm .

5.2.3 Measurement of the CGA Bubble Diameter under Elevated Pressure

5.2.3.1 Experimental Set-up

Experiments were conducted to determine how the CGA size changes with pressure. Figure 5-3 shows the experimental set-up. The set up consists of a Jerguson cell, a pump, a microscope, a camera and a computer.

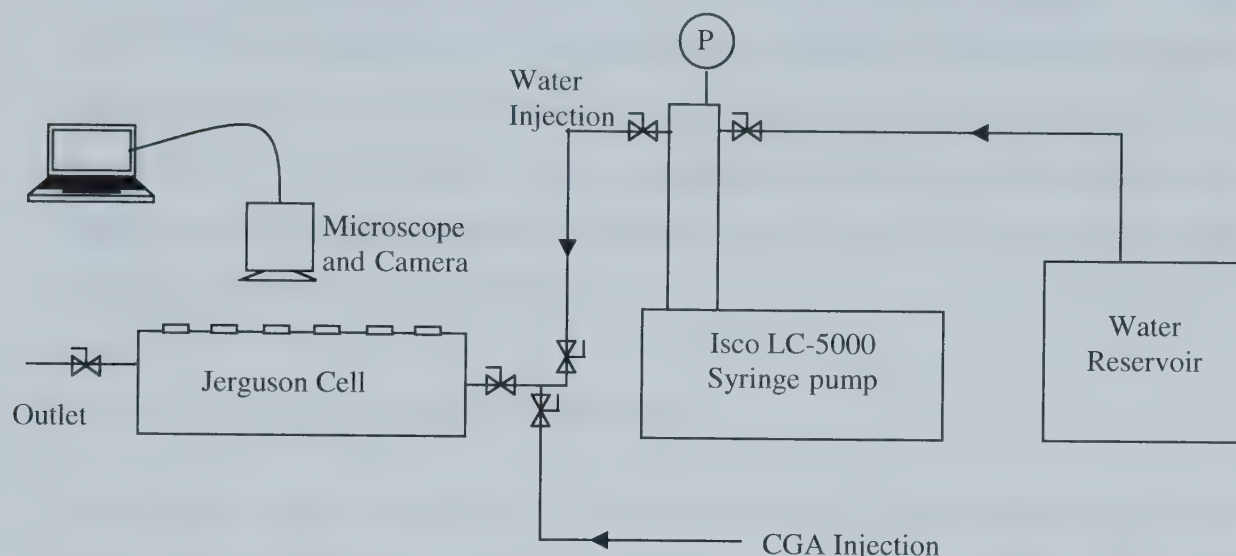


Figure 5-3: Experimental set-up

5.2.3.2 Experimental Procedure

Initially, the cell was filled with water via the pump. Care was taken to ensure that there was no air in the cell as well as in the connection lines. The pump line was then closed and the aphronized fluid was then injected into the cell via a syringe and a separate line. An initial picture of the CGAs was then obtained. Then, the outlet line was closed as well as the CGA inlet line. The cell valve was then opened and the pump was started at a slow rate. Water was used as the pressurizing fluid. Since the Jerguson cell window is much larger than the area obtained in the picture via the stereomicroscope, care was taken to ensure that the bubbles in the initial image were maintained in the focus while the pump was running. The pump was allowed to run until a pressure of 50 psig was reached. An image of the CGAs was then taken. This process was continued at 50 psig intervals up to 500 psig. The cell was then de-pressurized and an image of the

CGAs was taken once the cell pressure reached atmosphere. The pictures were then analyzed using the procedure outlined in Section 5.2.2.

5.2.4 *Measurement of the CGA Bubble Diameter under Elevated Temperature*

In order to study the effect of temperature on aphronized fluid, the polymer base fluid that is used to build the CGA fluid was transferred into a Napco E-Series Model 603 mechanical convection oven for 1 hour at a fixed temperature of either 50 or 75°C after preparation. The polymer base fluid was then removed from the oven and the fluid was aphronized as usual. A sample of the aphronized fluid was transferred to a microscopic slide immediately following the aphronization. Digital pictures of the aphronized fluid were then taken and analyzed using the procedure outlined in Section 5.2.2.

5.3 INITIAL CGA BUBBLE DIAMETER

Experiments were conducted to identify the effects of surfactant type and concentration, polymer concentration, mixing speed, mixing time and water quality on the initial bubble diameter. The base fluid and CGA fluid were developed according to the procedure outlined in Chapter 3.

Figure 5-4 to Figure 5-10 illustrate results of the bubble size measurements from the various experiments. The figures depict the average bubble size as well as d_{90} , d_{50} , and d_{10} values. d_{90} , d_{50} , and d_{10} are defined as the diameter in which 90%, 50%, and 10%, respectively, of the bubble population are less than that diameter. A complete listing of the average values obtained can be found in Appendix B.

Figure 5-4 shows effect of surfactant concentration on the bubble size. When the surfactant concentration is less than the CMC (0.035 lb/bbl), the average CGA size is greater than when the surfactant concentration is greater than the CMC (1 lb/bbl) which coincides with Chaphalkar et al. (1993) observations for concentrations of surfactant ranging from 50 to 1000 ppm (0.0175 to 0.35 lb/bbl).

Figure 5-5 shows the effect of surfactant concentration on the bubble size with concentrations that are greater than the CMC. Anionic surfactant (DDBS) concentrations of 1 lb/bbl and 2 lb/bbl were used together with 3 lb/bbl polymer (XG) base solution for comparison. The average bubble diameter as well as the d_{90} , d_{50} , and d_{10} values remained fairly constant with a change in the surfactant concentration. The average bubble diameter for both tests was 60 μm . Results from Figure 5-4 and Figure 5-5 indicate that there is a critical value of surfactant concentration for which the CGA size does not change. This critical value lies above the CMC.

The effect of XG concentration of the base fluid on the CGA size is presented in Figure 5-6. Results showed that CGA bubble diameter did not change significantly as the polymer concentration was increased.

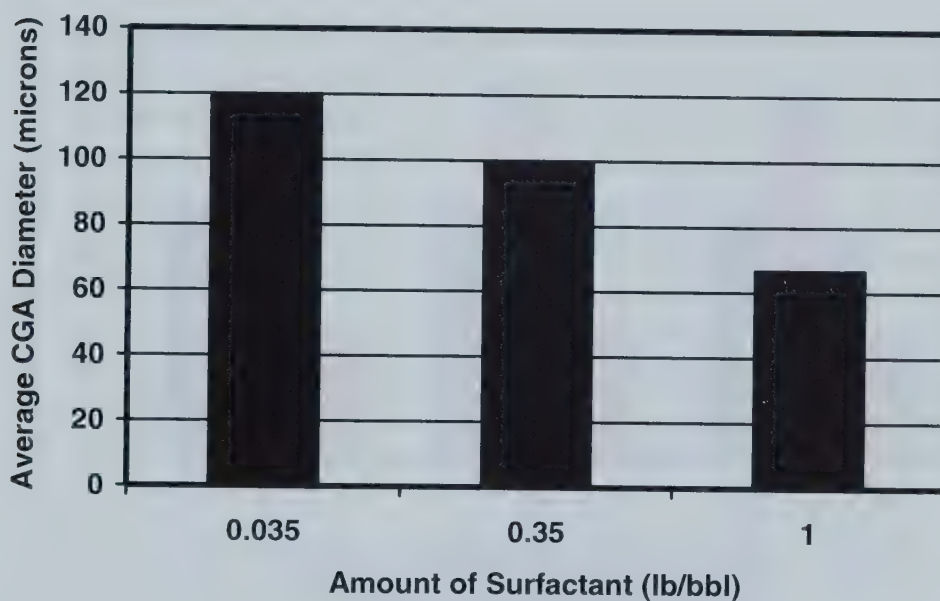


Figure 5-4: Effect of surfactant (DDBS) concentration on the average CGA diameter with 2 lb/bbl XG.

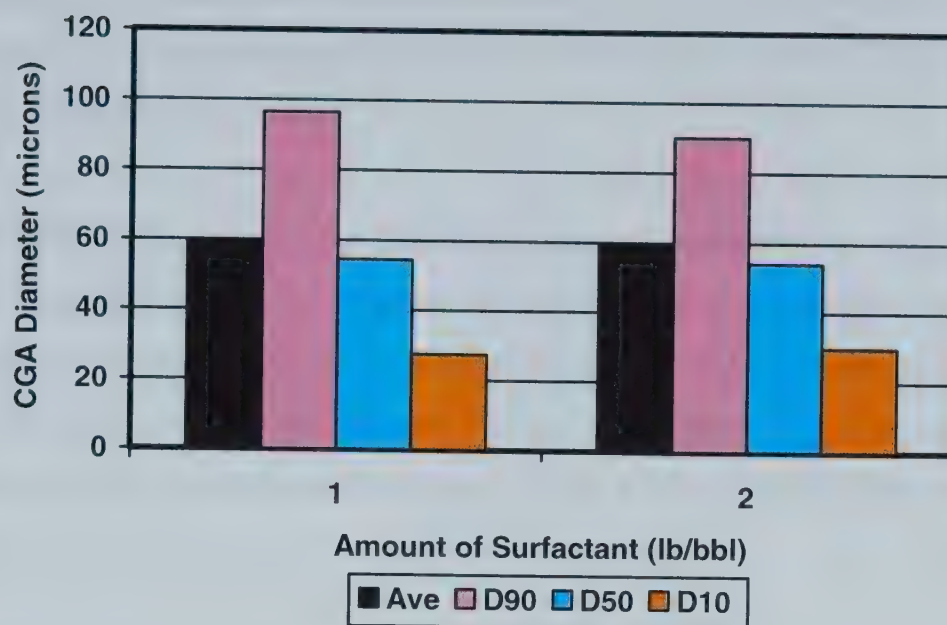


Figure 5-5: Effect of surfactant (DDBS) concentration on the CGA diameter with 3 lb/bbl XG.

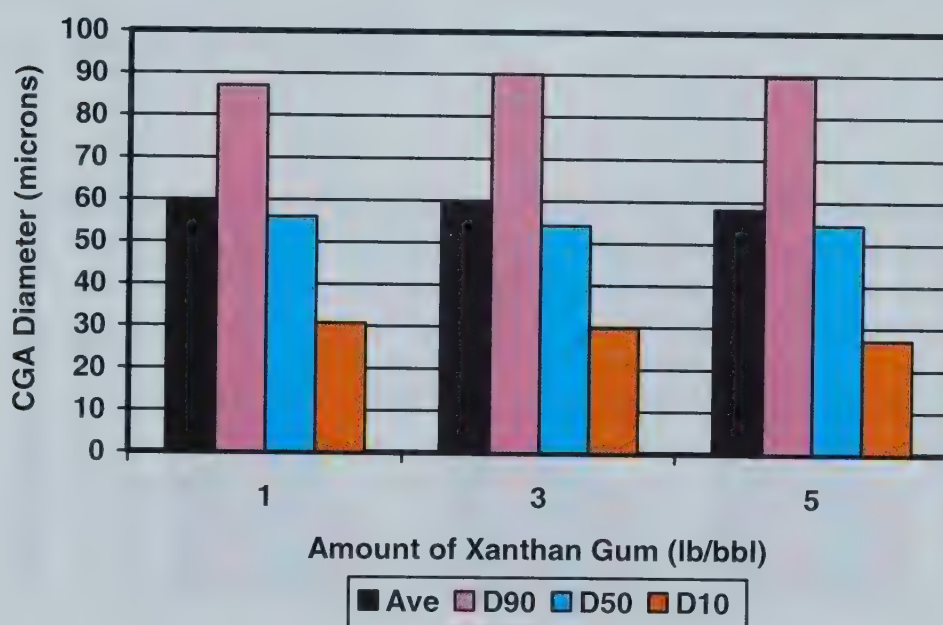


Figure 5-6: Effect of XG concentration on the CGA diameter with 2 lb/bbl DDBS.

Figure 5-7 illustrates the effect of mixing (shear) rate on the aphron diameter. The CGA diameter increases significantly (from 48 to 60 μm) as the mixing (shear) rate increases from low to medium mixing speed. From medium to high

mixing speed, the CGA diameter does not change. Since larger bubbles are more advantageous in pore blockage, a low shear rate is not as efficient in mixing the CGAs as the higher shear rate.

The effect of mixing time on the CGA size is shown in Figure 5-8. CGA bubble diameter increased from 60 to 72 μm as the mixing time was increased from 10 to 20 seconds. Increasing mixing time from 20 to 30 seconds, however, did not change the bubble size significantly. With an increase in mixing time, the temperature of the solution will increase. Since CGAs are not stable at higher temperature, it is advantageous to limit the mixing time.

The effects of using de-ionized water as compared to tap water on the CGA size development were investigated. As shown in Figure 5-9, CGA size did not change significantly depending on the type of water used. Since de-ionized water is not readily available in the field, these results indicate that one can use regular tap water as the base for the drilling mud.

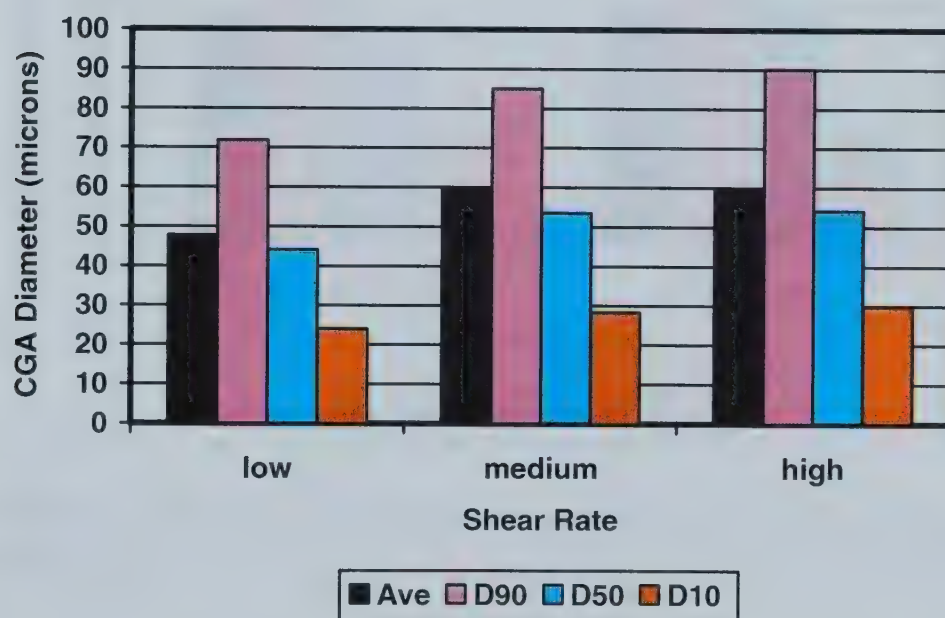


Figure 5-7: Effect of shear rate on the CGA diameter with 3 lb/bbl XG and 2 lb/bbl DDBS.

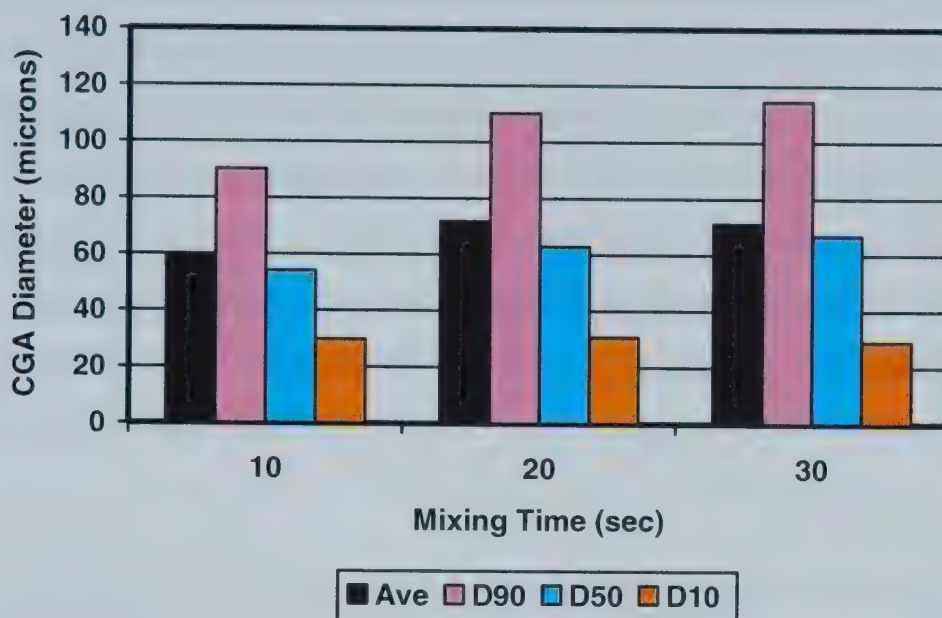


Figure 5-8: Effect of mixing time on the CGA diameter with 3 lb/bbl XG and 2 lb/bbl DDBS.

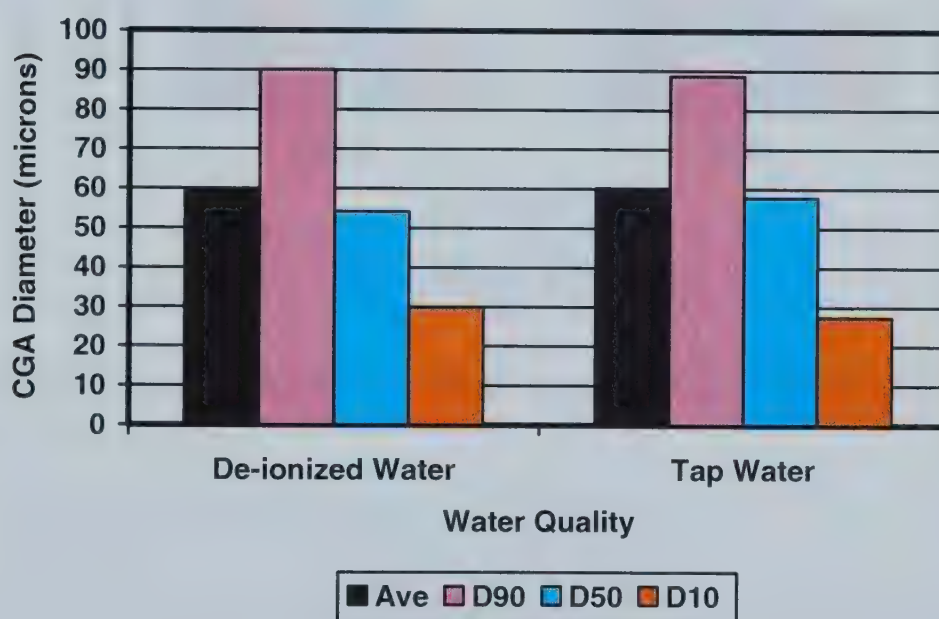


Figure 5-9: Effect of water type on the CGA diameter with 3 lb/bbl XG and 2 lb/bbl DDBS.

The effect of surfactant type on the CGA bubble size was investigated (Figure 5-10). The bubble size distribution of CGAs generated by using 1 lb/bbl anionic surfactant (DDBS) and cationic surfactant (HTAB) surfactants were compared.

The average diameter of the cationic surfactant (HTAB) based CGAs (90 μm) was found to be significantly larger than that of the anionic surfactant (DDBS) based CGAs (60 μm). Larger bubble diameters should result in a greater blocking ability. However, the combination of the polymer base fluid and the cationic surfactant created a hair-like solid particle within the fluid (See Figure 3-17). This hair-like solid particle will have a great effect on the blocking ability of the fluid and therefore it is not recommended to use the cationic surfactant (HTAB) with the polymer (XG) base fluid.

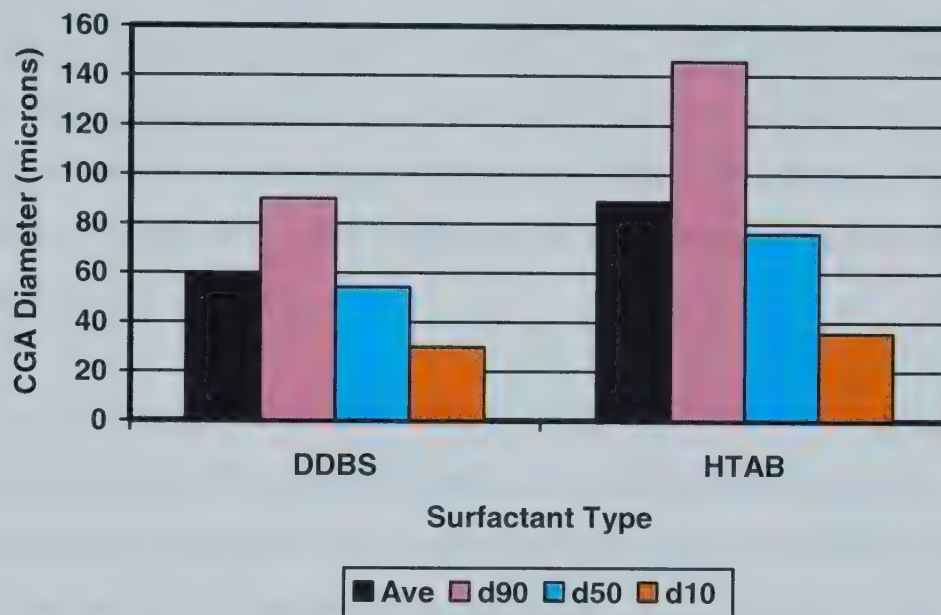


Figure 5-10: Effect of surfactant type on the average CGA diameter with 3 lb/bbl XG and 1 lb/bbl DDBS.

5.4 CHANGE IN CGA DIAMETER WITH TIME

The change of the CGA bubble diameter with time is an important factor for determining the ability of the bubble to block rock pores. The change in diameter relates to the stability of the CGA. The longer the CGA resists a change in diameter, the more stable the CGA is. The greater the stability, the greater potential that fluid has for blocking pores for an extended period of time. Figure 5-11 shows an example of the images taken for analysis of bubble diameter with time.

Figure 5-12 illustrates the experimental results for the change in bubble size with time for different polymer (XG) concentrations. An increase in the polymer (XG) concentration decreases the degree of the bubble expansion with time thus confirming that an increase in viscosity of the base fluid increases the stability of the system. The figure also shows that the initial average bubble diameter is similar for all concentrations at approximately 70 μm . For the 3 lb/bbl polymer (XG) sample, it took four times longer to reach approximately the same bubble size (190 μm) than the 0.5 lb/bbl polymer (XG) sample. As well, a change in polymer (XG) concentration from 2 lb/bbl to 3 lb/bbl had little effect on the bubble size increase for the first 30 minutes. This indicates that increasing the polymer (XG) concentration above 2lb/bbl does not have a significant impact on retarding the bubble expansion in the short term. However, the rate of expansion between the 2 lb/bbl and 3 lb/bbl polymer (XG) concentrations does differ after 30 minutes.

The increase in bubble size with time for 3 different DDBS concentrations is given in Figure 5-13. The rate of bubble growth as a function of time (i.e. bubble deformation rate) decreased as the surfactant concentration increased. Increasing DDBS concentration decreased the initial bubble size. The initial bubble size of the 0.035 lb/bbl and 1lb/bbl solutions were 120 μm and 67 μm , respectively.

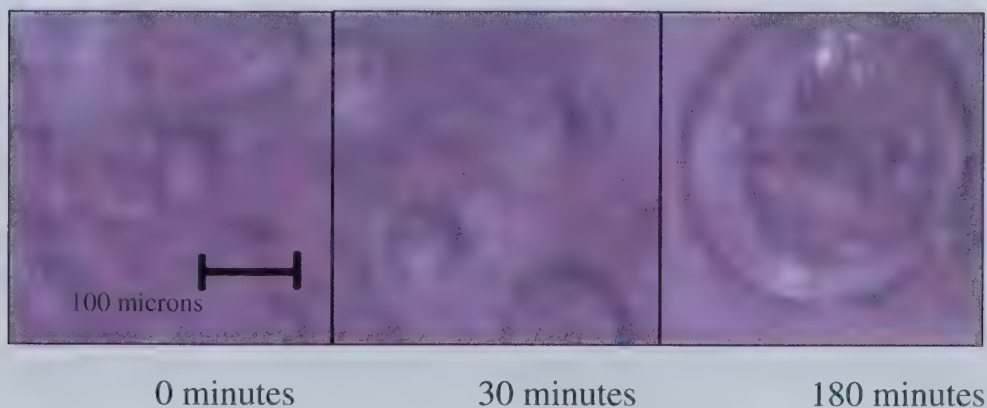


Figure 5-11: Sample of images taken for CGA bubble size with time.

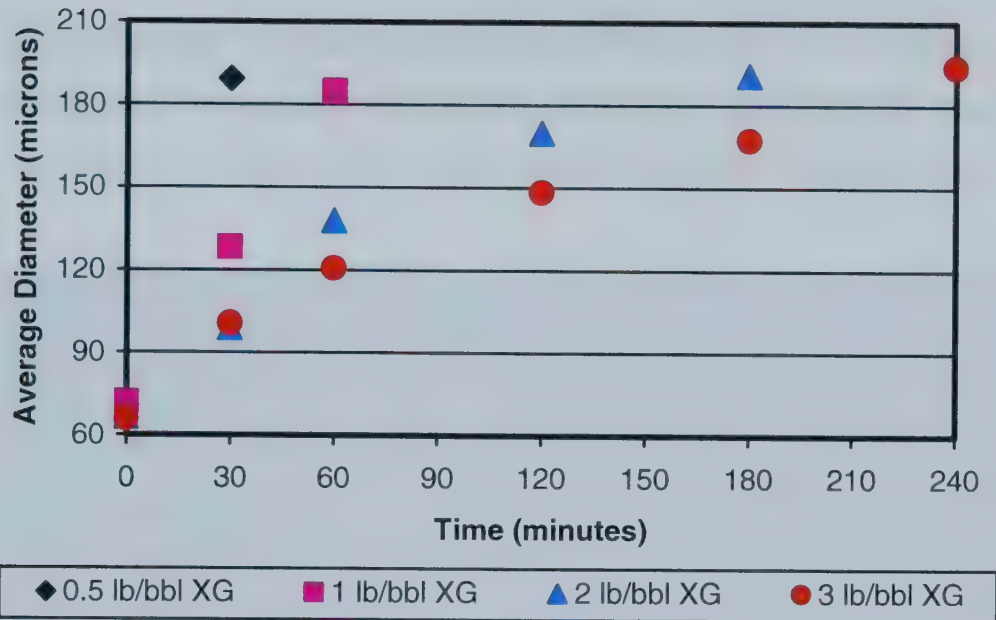


Figure 5-12: Effect of time and polymer (XG) concentration with 1 lb/bbl surfactant (DDBS) on the average diameter of the CGA bubble.

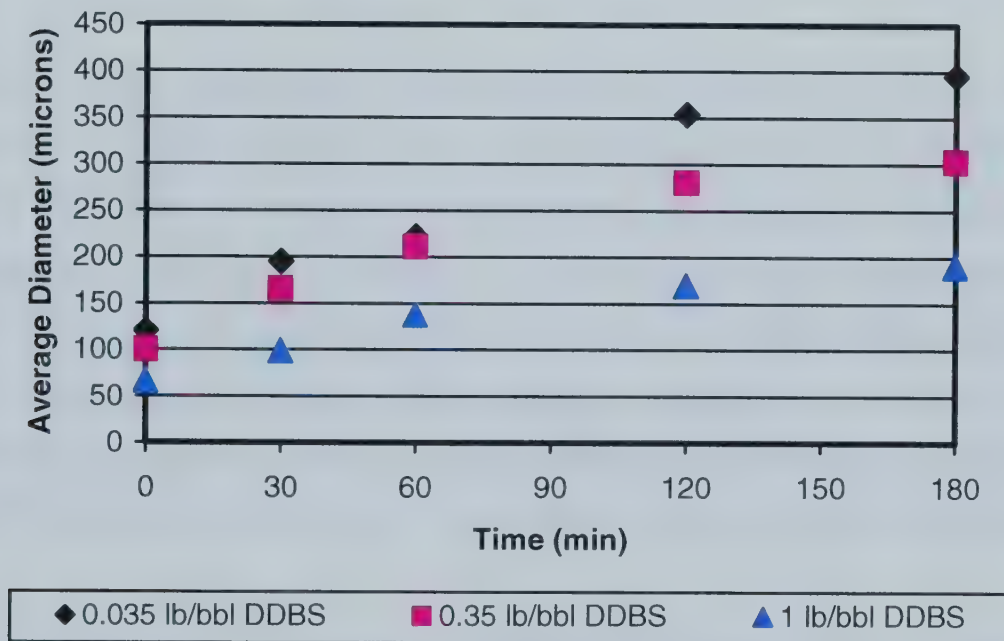


Figure 5-13: Effect of time and surfactant (DDBS) concentration with 2 lb/bbl polymer (XG) on the average diameter of the CGA bubble.

5.5 CHANGE IN CGA DIAMETER UNDER ELEVATED PRESSURE

The change of the CGA bubble diameter with increasing pressure is needed in order to understand when the CGA will block porous media. As the pressure of

the borehole increases with increasing depth, the CGA is expected to decrease in size. The magnitude to which this occurs will determine the blocking ability. Experiments were conducted under elevated pressure to determine this magnitude. Figure 5-14 shows a sample of the images obtained during these experiments.

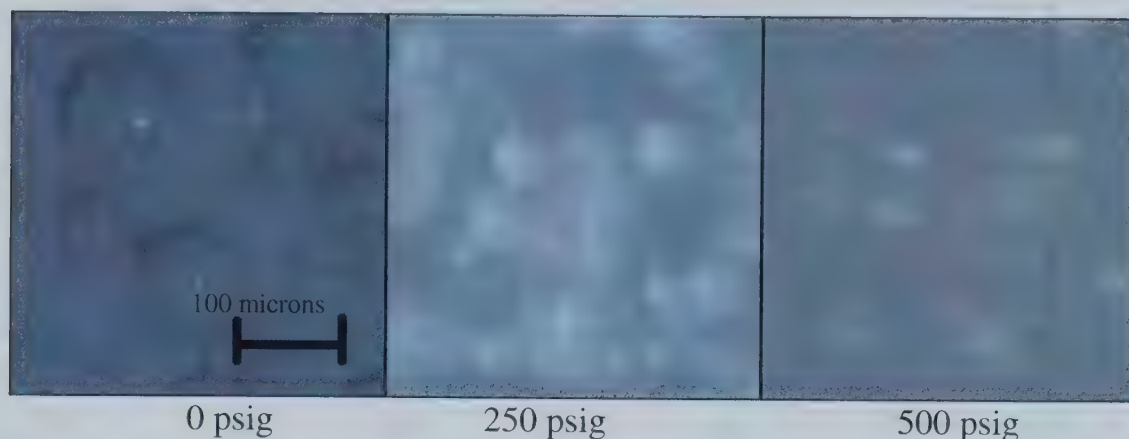
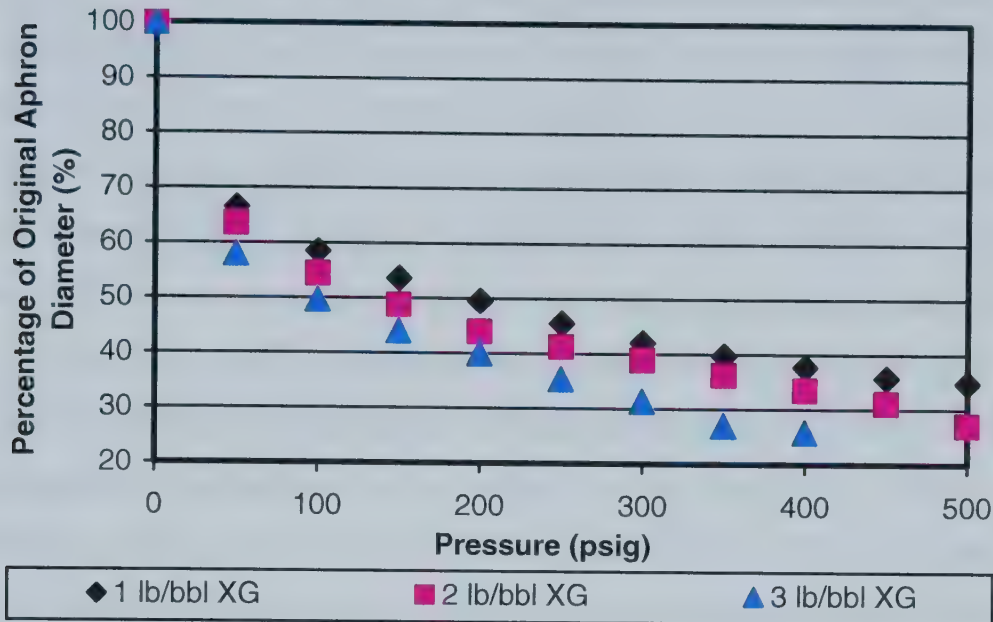


Figure 5-14: Sample of images taken for CGA bubble size with an increase in pressure.

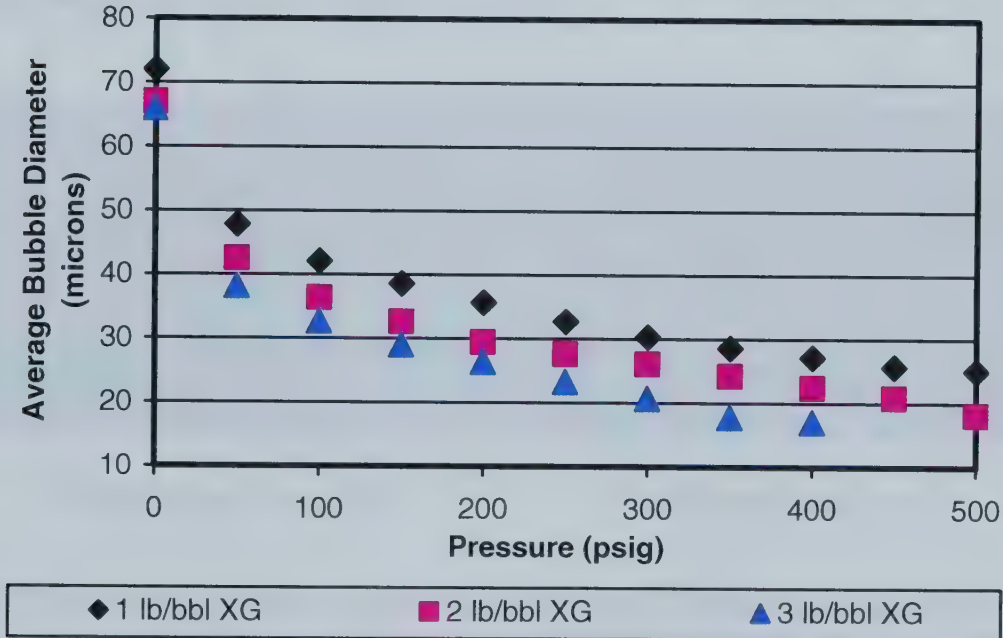
Elevated pressure experiments were conducted by using CGA based drilling fluids with 3 different polymer (XG) concentrations. Figure 5-15a illustrates the percent change in the original bubble size as the pressure is increased from atmospheric condition up to 500 psig. At 500 psig pressure, bubble sizes were reduced down to 36% and 28% of their original sizes at atmospheric condition for 1 lb/bbl and 2 lb/bbl polymer (XG) solutions, respectively. The bubble size decreased at a faster rate with an increase in polymer concentration indicating that a higher density base fluid has an adverse effect on the bubble size under pressure.

Figure 5-15b illustrates the changes in actual average bubble sizes as a function of pressure. At 500 psig, the average bubble size is approximately 25 μm for the 1 lb/bbl mixture and 18 μm for the 2 lb/bbl mixture. A value for the 3 lb/bbl concentration at 500 psig is not reported because the bubble size exceeded the lower limit of the optics of the stereoscope system. This again indicates that increasing the base fluid density, decreases the size of the CGA under pressure. Therefore it is important to design a CGA fluid that has a polymer concentration

great enough to resist instabilities with time but that also has a polymer concentration that is minimized to reduce the effects of pressure on the CGA.



a



b

Figure 5-15: a) Change in percentage of original CGA size with pressure for various concentrations of polymer (XG) and 1 lb/bbl surfactant (DDBS); b) Change in average bubble diameter with pressure for various concentrations of polymer (XG) and 1 lb/bbl surfactant (DDBS).

Figure 5-16 shows a picture of the CGA bubbles before pressurization and after the pressure had been increased to 500 psig and decreased back to 0 psig. Bubble sizes of the 1 lb/bbl polymer (XG) solution did increase slightly due to de-pressurization following an initial increase of pressure up to 500 psig. The bubble size of the 3 lb/bbl polymer (XG) solution, however, increased significantly after de-pressurization. Figure 5-17 shows a comparison of the how average bubble size changed after pressurizing to 500 psig and de-pressurizing to 0 psig of three different polymer (XG) solutions. The average bubble diameter of 3 lb/bbl polymer (XG) solution increased drastically from approximately 70 μm to almost 300 μm (more than 400%), whereas the average bubble diameter of 1 lb/bbl polymer (XG) solution increased from 70 μm to only 110 μm (57%). Since the CGA diameter size decreases at a faster rate for the higher polymer (XG) concentrations and it was observed that the CGAs for the 3 lb/bbl polymer (XG) base fluid disappeared at 500 psig, it can also be assumed that the air in the core of the CGAs that disappeared diffused into the polymer base fluid and coalesced forming larger bubbles upon depressurization.

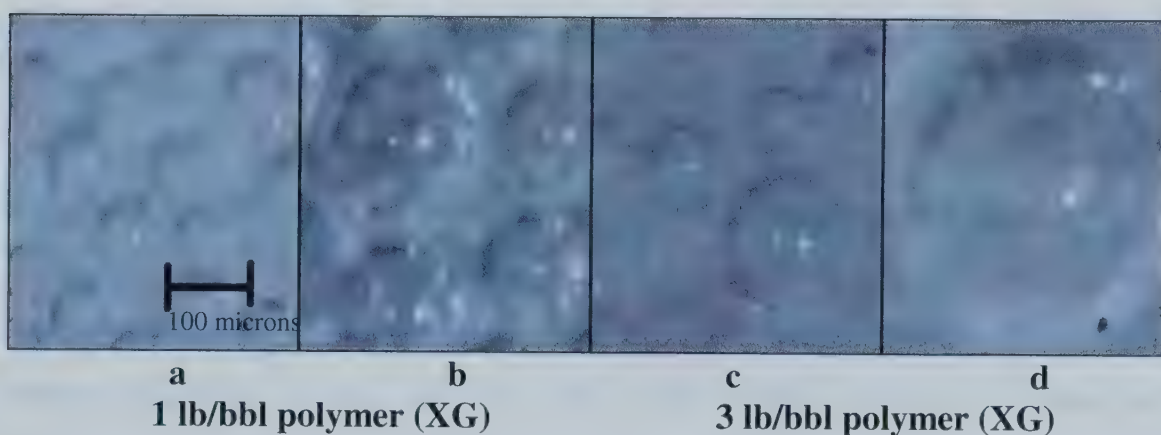


Figure 5-16: a) CGAs before pressurization, 0 psig, 1 lb/bbl polymer (XG), 1 lb/bbl surfactant (DDBS); b) CGAs after pressurization up to 500 psig and de-pressurization back to 0 psig, 1 lb/bbl polymer (XG), 1 lb/bbl surfactant (DDBS); c) CGAs before pressurization, 0 psig, 3 lb/bbl polymer (XG), 1 lb/bbl surfactant (DDBS); d) CGAs after pressurization, up to 500 psig and de-pressurization back to 0 psig, 3 lb/bbl polymer (XG), 1 lb/bbl surfactant (DDBS).

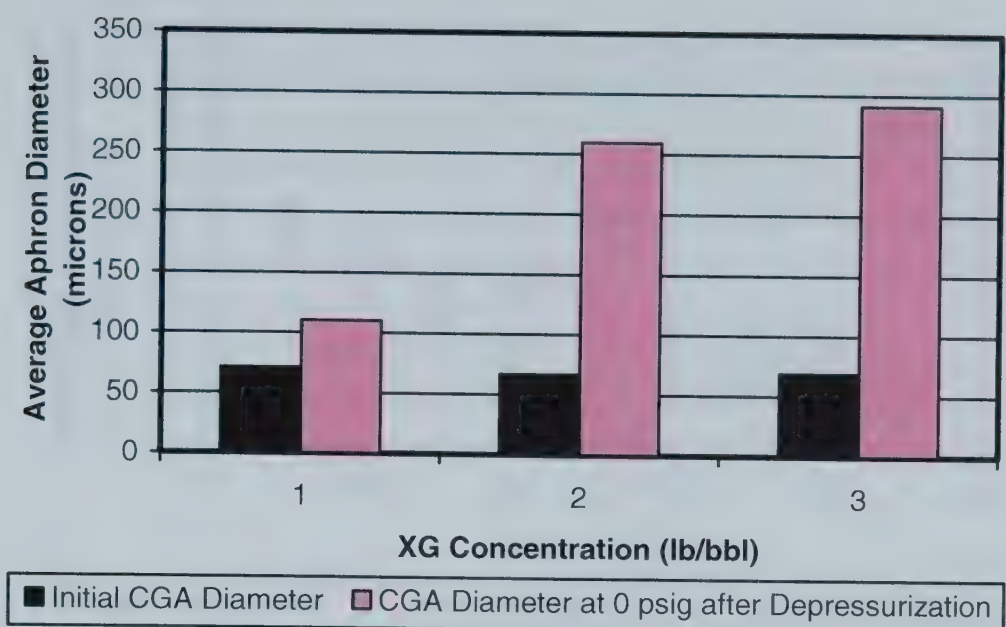


Figure 5-17: Comparison of change in bubble size for various concentrations of polymer (XG) with 1 lb/bbl surfactant (DDBS) at 0 psig before and after pressurization.

The effect of pressure on the bubble size of the solutions prepared with different anionic surfactant concentration (DDBS) is shown in Figure 5-18a and Figure 5-18b. Figure 5-18a gives the percent reduction of the bubble size with pressure while Figure 5-18b shows the change in diameter in terms of actual average bubble size. Increasing the surfactant concentration decreased the rate of reduction of CGA diameter with pressure. For example, the average bubble size of the solution with 0.035 lb/bbl surfactant concentration is larger than that of the solutions with higher surfactant concentration at 0 psig. However, the average bubble diameter of the solution with 0.035 lb/bbl surfactant concentration becomes smaller than that of the other samples at 500 psig. In Figure 5-18a, it is also evident that the change in CGA diameter for the 0.035 lb/bbl surfactant (DDBS) concentration is greater than the of both the 0.35 and 1 lb/bbl surfactant (DDBS) concentrations indicating that the decrease in diameter due to pressure is greater with surfactant concentrations that are less than the CMC value.

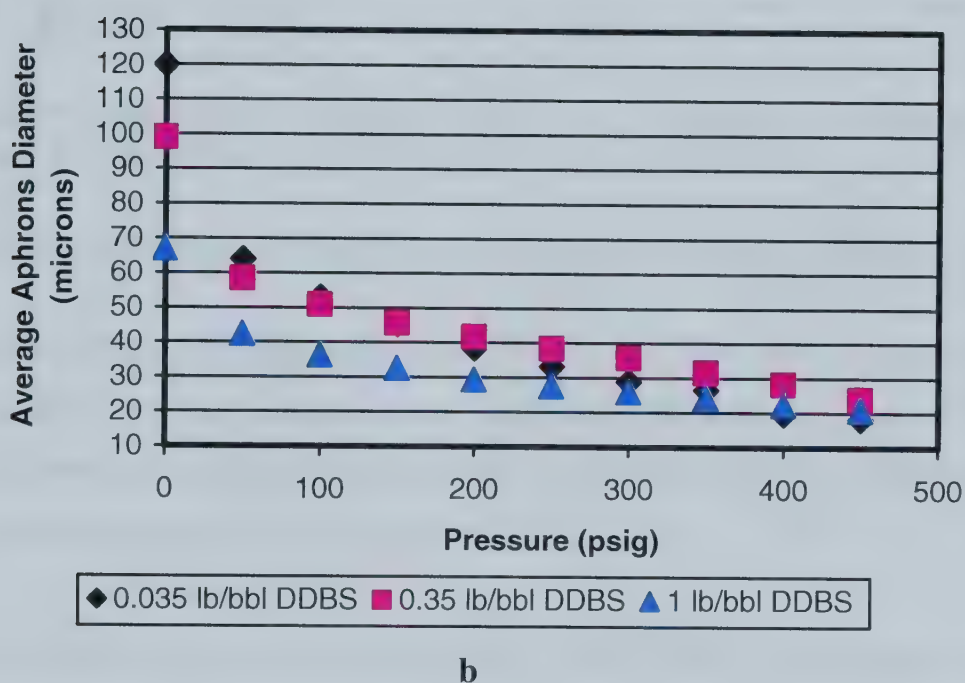
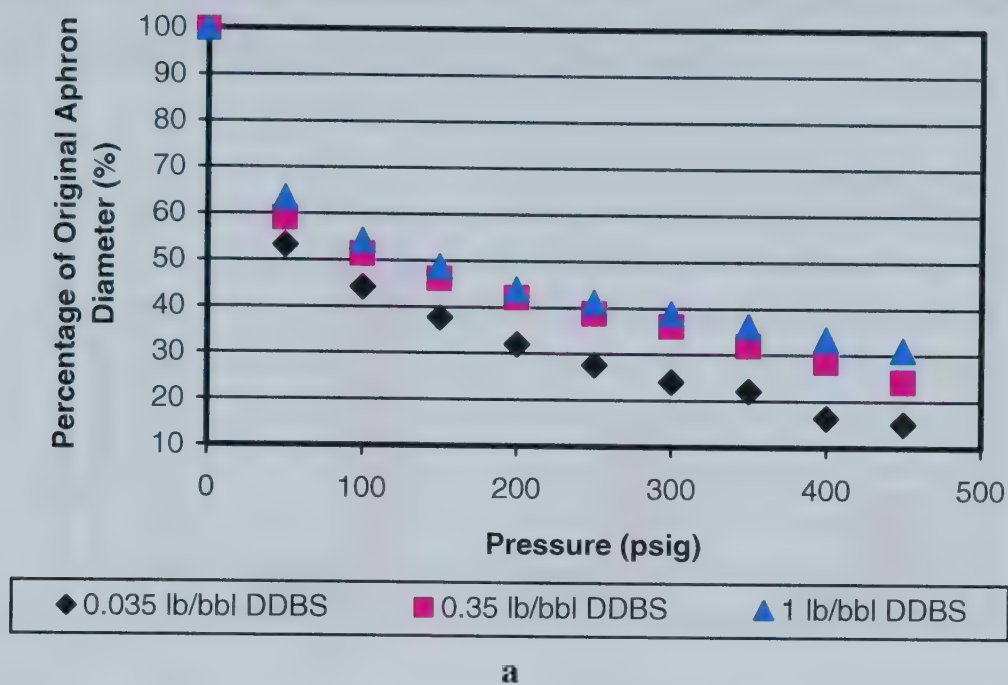


Figure 5-18: a) Change in percentage of original CGA size with pressure for various concentrations of DDBS and 2 lb/bbl XG; b) Change in average bubble diameter with pressure for various concentrations of DDBS and 2 lb/bbl XG.

Figure 5-19 illustrates the change in bubble size after pressurizing the bubbles up to 500 psig and de-pressurization back to 0 psig with a change in DDBS. It shows

that higher the surfactant concentrations, the smaller the change in bubble size after the sequence of pressurization and de-pressurization.

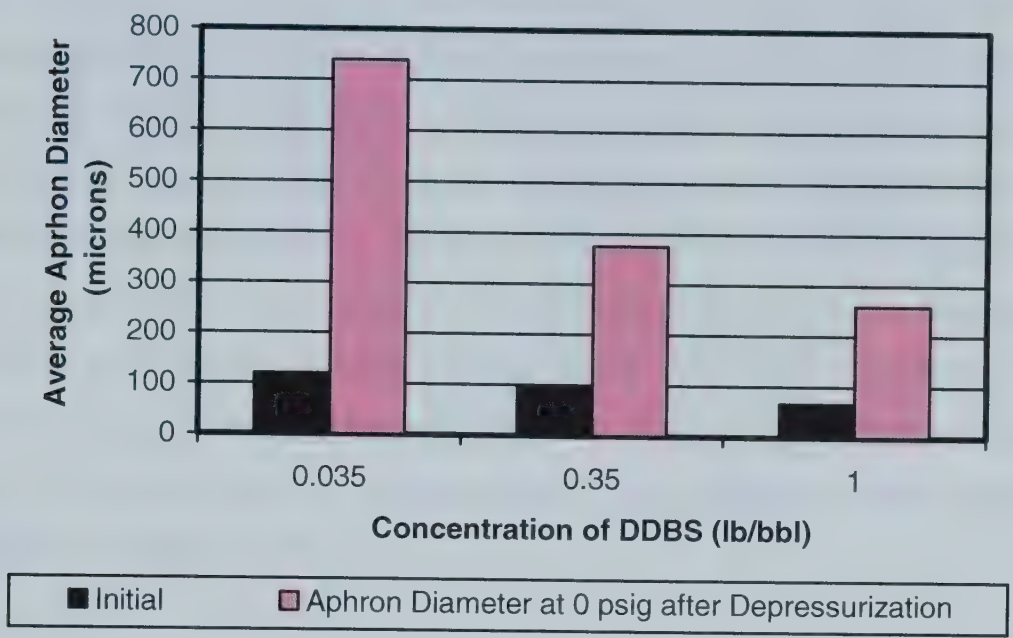


Figure 5-19: Comparison of change in bubble size for various concentrations of DDBS and 2 lb/bbl XG at 0 psig before and after pressurization.

5.6 CHANGE IN CGA DIAMETER UNDER ELEVATED TEMPERATURE

Temperature is also an important factor in sizing CGA fluid for blocking of porous media. As the temperature of the borehole increases, there will be a change in stability and CGA diameter size. Understanding this change will help in the understanding of the blocking of the pores.

Figure 5-20 shows the average micro-bubble sizes of the solutions with 1 and 2 lb/bbl polymer (XG) concentrations measured at base fluid temperatures of 25, 50 and 75°C. Larger bubble sizes were generated at higher base fluid temperatures. For the 2 lb/bbl polymer (XG) sample, however, the increase in bubble size with temperature was slightly less than the 1 lb/bbl polymer (XG) solution, indicating the stabilizing effect of high polymer (XG) concentrations on the bubble size. Between the 25°C and the 50°C interval bubble sizes changed at a faster rate than

that of the temperature interval from 50°C to 75°C, indicating that CGAs seem to be more sensitive to temperature change at lower temperatures.

Figure 5-21 shows the effect of temperature on the average bubbles sizes of the solutions with 0.035 lb/bbl and 1 lb/bbl surfactant (DDBS) concentrations and 2 lb/bbl polymer(XG) concentrations. Increasing the base fluid temperature did not have a significant effect on the initial bubble sizes of the solution with 0.035 lb/bbl surfactant concentration. However, the initial CGA size was already much higher than the normal average CGA size indicating that at this level of surfactant, the CGAs were already unstable. Initial bubble size of the fluid with 1 lb/bbl surfactant concentration increased significantly (50%) as the temperature changed from 25°C to 50°C and at a slower rate (15%) afterward when temperature changed from 50°C to 75 °C.

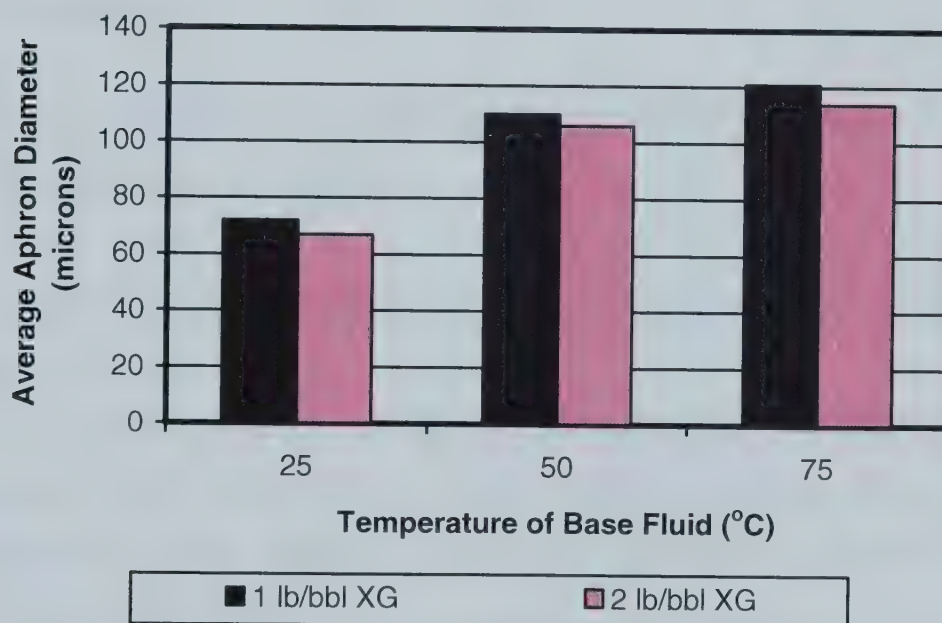


Figure 5-20: Change in CGA diameter for different temperatures and polymer (XG) concentrations with 1 lb/bbl surfactant (DDBS).

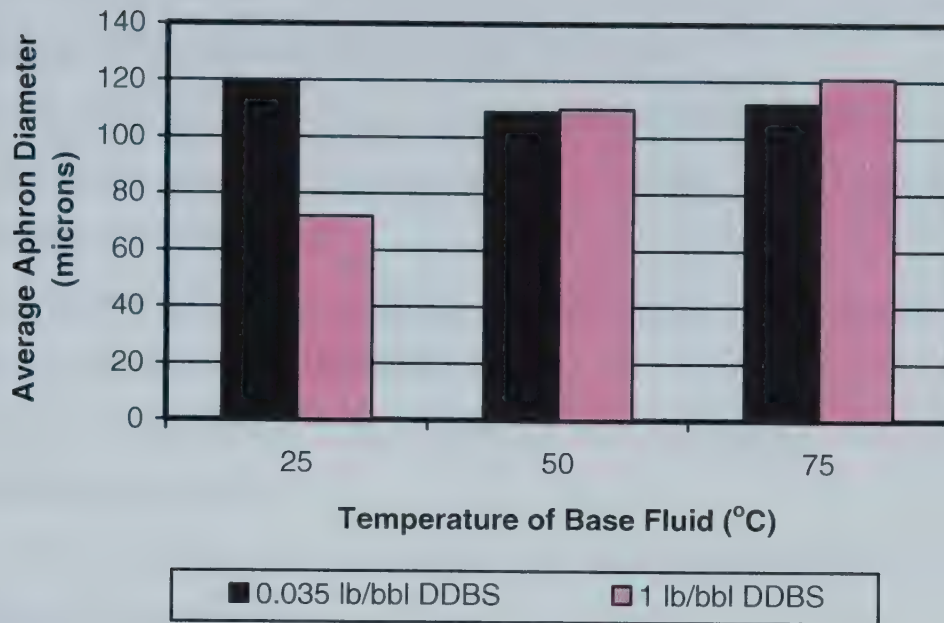


Figure 5-21: Change in CGA diameter for different temperatures and DDBS concentrations with 2 lb/bbl XG.

5.7 SUMMARY

Based on the results of the experiments carried out on the CGA bubble size, the following conclusions can be drawn:

- Larger CGAs were created when the fluid was mixed at higher mixing (shear) rates.
- CGA sizes increased as the mixing time increased from 10 seconds to 20 sec. However, bubble sizes did not change significantly from 20 to 30 sec., indicating that there might be an optimum mixing time period to obtain maximum bubble size.
- CGA sizes generated by using cationic surfactants were larger than the ones generated by using anionic surfactants.
- Initial average CGA diameter was similar for all polymer (XG) concentrations. As polymer concentration increased, however, the bubble growth rate with time decreased.

- Increasing the polymer (XG) concentration above 2lb/bbl did not have any significant effect on retarding the bubble growth rate.
- An increase in surfactant concentration decreased the initial bubble size when the surfactant concentration was less than or near to the critical micelle concentration (CMC).
- Increasing the surfactant concentration decreased the bubble growth rate with time (i.e., more the micro-bubbles).
- The bubble size decreased at a faster rate with increasing pressure at higher polymer concentrations.
- The bubble size decreased at a slower rate with increasing pressure at higher surfactant concentrations.
- Bubbles were unstable (i.e. bubbles were larger than their original size) when they are exposed to de-pressurization process following the pressurization.
- Increasing the temperature of the base fluid, increased the diameter of the CGA at surfactant concentrations higher than critical micelle concentration (CMC). The temperature effect on the bubble size was not significant at surfactant concentrations below CMC.
- Temperature effect on the bubble size decreased as the polymer concentration increased.
- At low surfactant concentrations, increasing temperature did not have significant effect on the bubble size.
- Between 25°C and the 50°C the increase in bubble size was more drastic than from 50°C to 75°C, indicating that the CGAs are more sensitive to temperature change at lower temperatures.

6 VISUAL INVESTIGATION OF THE CGA BRIDGING MECHANISM

CGAs in the drilling fluid are expected to form a bridge-like structure across rock surface due to the Jamin effect. The CGA diameter and pore diameter are major factors in controlling this effect. As well, the interactions between the systems fluids are important. Micromodel experiments were conducted to understand the blocking ability of CGAs in porous media. The effect of pore/bubble size as well as the interaction between pore fluids and CGA based drilling fluids is investigated.

6.1 EQUIPMENT AND MATERIALS USED FOR THE VISUALIZATION STUDY OF THE CGA BRIDGING MECHANISM

6.1.1 *Equipment Used for the Visualization Study*

A picture of the micromodel cell utilized in this study is given in Figure 6-1. Figure 6-2 shows a schematic of the micromodel cell. The micromodel cell is composed of three glass plates that are held firmly together by an aluminum house. In between the glass plates and the aluminum house is a rubber gasket. The bottom plate is a solid glass support plate. The centre plate has an etched portion which acts as a simulated porous medium. The upper glass plate has two holes which provide communication to the matrix. Plastic tubing is inserted into the holes and held in place with silicone sealant. Two micromodels (etched glass portions) were used for this study. Figure 6-3 illustrates the matrix of each model. Each matrix is 9 x 9 cm and on the injection and production side of the etched portion is a 9 x 0.5 cm spacer which allows communication between the etched portion and the upper injector plate. The matrix is composed of circular rock bodies and flow paths. For matrix 1, the rock bodies are not connected allowing for ease of flow. This is not the case with matrix 2. Some of the rock bodies are connected which in turn reduces the permeability. Table 6-1 lists the parameter of each matrix.



Figure 6-1: Micromodel used in study.

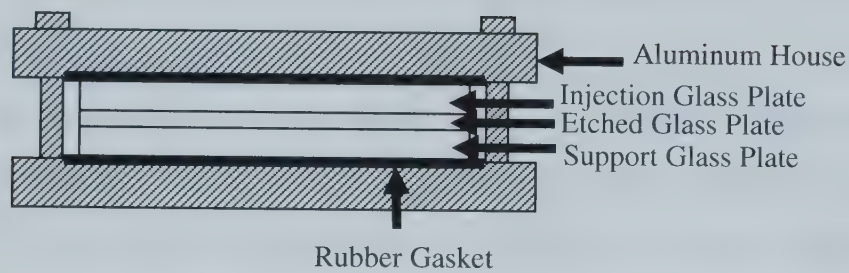


Figure 6-2: Schematic of the micromodel used in study.

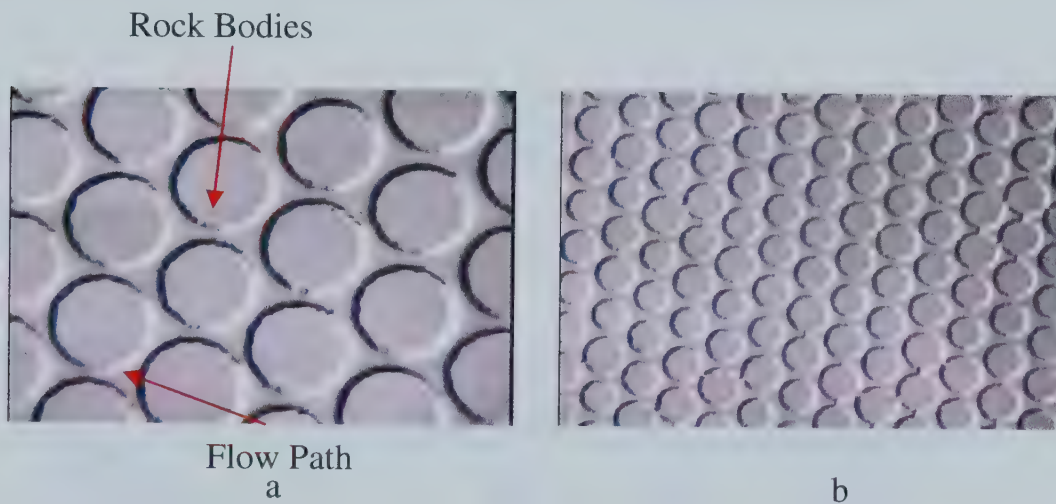


Figure 6-3: a) matrix 1, 1.6x magnification, b) matrix 2, 1.6x magnification

For the micromodel experiments pressure was measured at the inlet and outlet of the micromodel using a Rosemount® differential pressure transmitter. Pressure

values were recorded using an Agilent® Data Acquisition. A Quizix (QX-1500) pump was used to inject the fluid.

Table 6-1: Parameters of the micromodels

	Permeability (mD)	Pore Volume (cc)	Pore Throat Diameter (μm)	Pore Depth (μm) (apprx.)
Matrix 1	200	0.17	72	50
Matrix 2	50	0.09	60	21

6.1.2 *Materials Used for the Visualization Study*

A polymer (XG) – water mixture was used as the base drilling fluid. The base fluid was prepared using a similar method described in Chapter 3. A Waring commercial blender was used to mix the fluid. The base fluid was aphronized by using a Polytron Generator for 30 second duration and sodium dodecyl benzene sulfonate (DDBS), an anionic surfactant, was added to the base fluid for aphronization. Concentrations of 0.5 to 3 lb/bbl were used for the polymer (XG) base fluid and 0.035 to 2 lb/bbl for the anionic (DDBS) surfactant.

The properties of the reservoir fluids can be found in Table 6-2. The formula used to make the brine in this study was developed from a typical Lloydminster, Alberta reservoir brine.

Table 6-2: Fluids used for the visualization study.

Fluid	Viscosity at 22°C (cP)	Density (g/cc)
Brine	1	0.99
Mineral Oil	80	0.87
Crude Oil	7	0.85

6.2 EXPERIMENTAL PROCEDURE USED FOR THE VISUALIZATION STUDY OF THE CGA BRIDGING MECHANISM

6.2.1 Experimental Set-Up

A schematic of the experimental set-up is given in Figure 6-4. The experimental set-up consists of a pump, two accumulators used to inject the CGA fluid and the reservoir fluid, the micromodel, differential pressure transducer and a data acquisition system which recorded at intervals of 10 seconds. Video images of the micromodel were taken for the duration of the tests via a microscope, camera and computer. All image taken during these tests can be found in Appendix C.

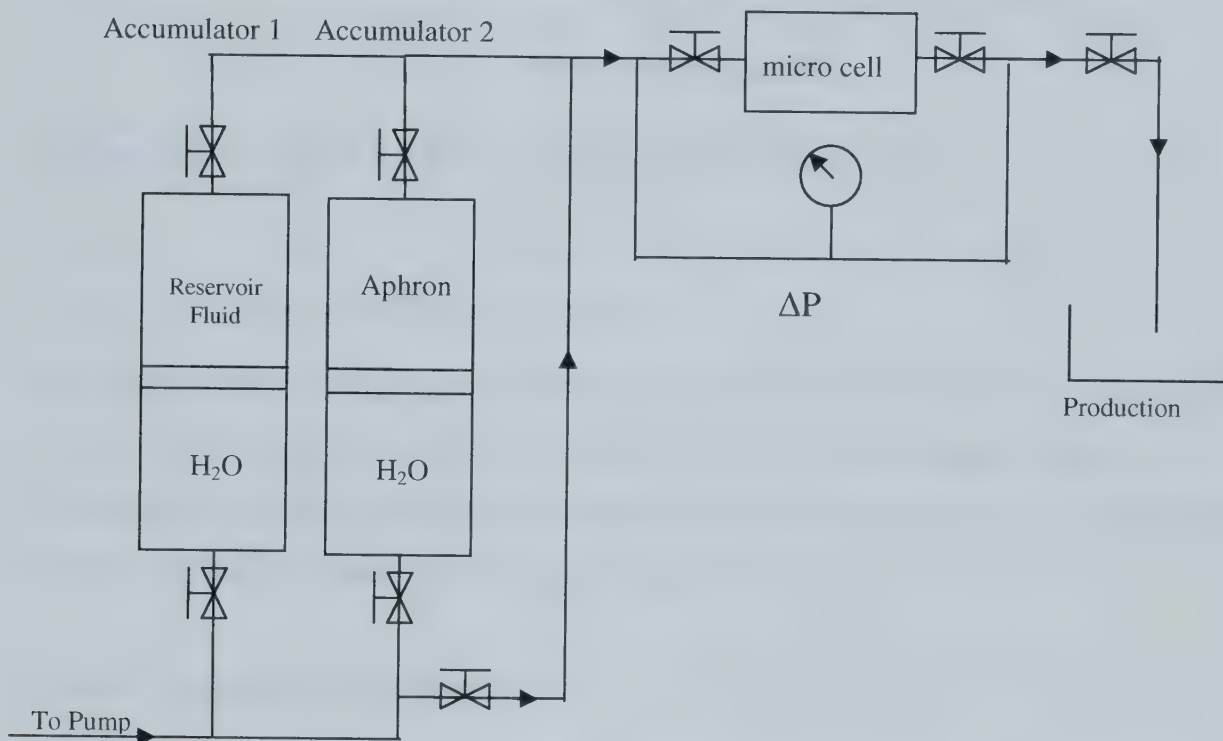


Figure 6-4: Experimental flow diagram

6.2.2 Experimental Procedure

Figure 6-5 is a sample of the results obtained during the experiments. Overall, the experiment can be divided into three sections: saturation fluid injection, CGA fluid injection and the saturation fluid re-injection. Only the CGA fluid injection

and the saturation fluid re-injection are represented in Figure 6-5 and are divided into sections 1 and 2 respectively.

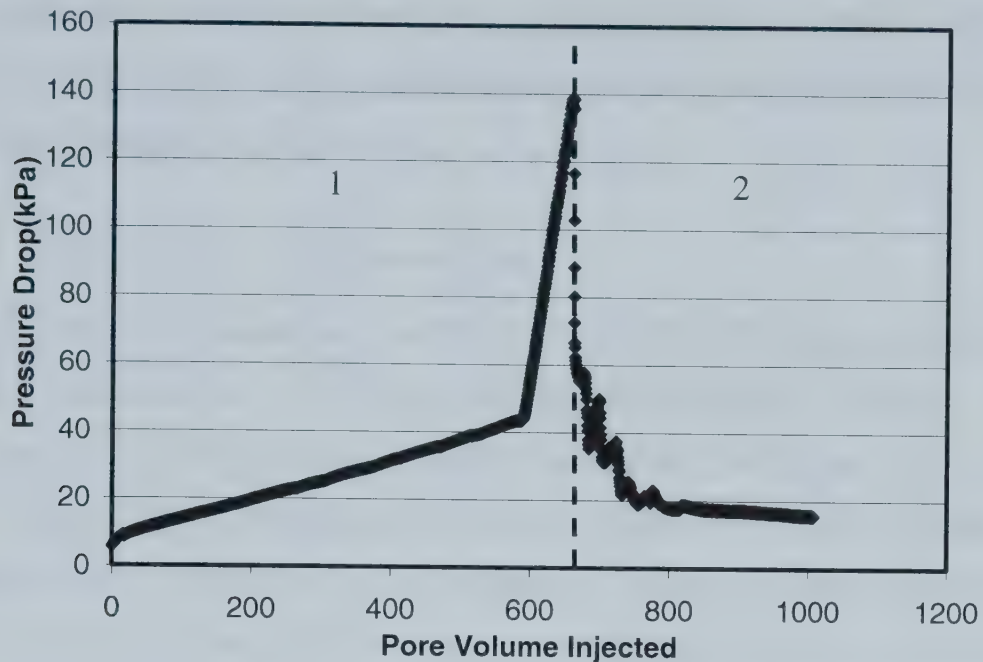


Figure 6-5: Sample results from the micromodel experiments

6.2.2.1 Injection of the Saturation Fluid

The micromodel was initially saturated with the saturation fluid. The saturation fluid was injected into the micromodel via the accumulator (Figure 6-4). Saturation was achieved by injecting more than 10 PV (pore volumes) of the fluid and by cycles of pressure build-up and release.

6.2.2.2 Injection of CGA Fluids

The aphronized fluid is pumped into the cell from the accumulator. Pressure drop across the cell was measured with the differential pressure transmitter. The outlet pressure was maintained at atmospheric condition for all runs. The aphronized fluid was injected at a fixed flow rate into the micromodel until the pressure limitation of the cell was reached or instability of the CGA fluid was observed. The specific flow rate used was slow enough so that the pressure rise in the micromodel was not drastic but fast enough so that the CGA fluid would not coalesce. Instability was observed when a loss of pressure in the cell occurred

due to large air slugs in the injection line. Once the pressure limitation was reached or instability was observed, the CGA fluid injection was stopped and reservoir (initial saturation) fluid was re-injected into the cell. During the injection of the CGA fluid, a pressure rise is observed in the micromodel as indicated by Section 1 of Figure 6-5.

6.2.2.3 Re-Injection of the Saturation Fluid

The reservoir (initial saturation) fluid was re-injected at the same rate as the CGA fluid and was continued until a constant pressure drop was observed. The re-injection of the saturation fluid is shown in Section 2 of Figure 6-5. Initially, there is a rise in pressure drop once the fluid was switched from CGA fluid to the saturation fluid. This is due to the difference in pressure between the inlet and outlet of the accumulator and a difference in pressure between the CGA fluid and the saturation fluid that is being injected. Another factor controlling this is the difference in compressibility between saturation fluid and the CGA fluid. Since the saturation fluids are incompressible fluids, at the initial point when the fluid is switched to water, there is a greater pressure drop across the micromodel. Once the water reaches the micromodel, the CGA fluid is flushed out of the micromodel and the pressure drop then decreases. As the water injection continues, the pressure drop stabilizes and reaches near to the initial water injection pressure level, indicating that all of the CGA fluid is removed from the micromodel.

Table 6-3 lists the experiments conducted and the parameters used for those experiments.

Table 6-3: Visualization experiments conducted.

Run #	Experiment #	Saturation Fluid	Polymer (XG) Conc. (lb/bbl)	Surfactant (DDBS) Conc. (lb/bbl)	Flow Rate (cc/min)	Matrix
1	W-P1-S2-R1-M1	Water	1	2	1	1
2	W-P0.1-S2-R0.5-M1	Water	0.1	2	0.5	1
3	W-P0.5-S2-R0.5-M1	Water	0.5	2	0.5	1
4	W-P1-S2-R0.5-M1	Water	1	2	0.5	1
5	W-P2-S2-R0.5-M1	Water	2	2	0.5	1
6	W-P3-S2-R0.5-M1	Water	3	2	0.5	1
7	W-P1-S0.035-R0.5-M1	Water	1	0.035	0.5	1
8	W-P1-S1-R0.5-M1	Water	1	1	0.5	1
9	W-P2-S0-R0.5-M1	Water	2	0	0.5	1
10	W-P2-S0.035-R0.5-M1	Water	2	0.035	0.5	1
11	W-P2-S1-R0.5-M1	Water	2	1	0.5	1
12	W-P0.5-S2-R0.5-M2	Water	0.5	2	0.5	2
13	B-P1-S2-R1-M1	Brine	1	2	1	1
14	B-P0.5-S2-R0.5-M1	Brine	0.5	2	0.5	1
15	B-P1-S2-R0.5-M1	Brine	1	2	0.5	1
16	B-P2-S2-R0.5-M1	Brine	2	2	0.5	1
17	B-P2-S0.035-R0.5-M1	Brine	2	0.035	0.5	1
18	B-P2-S1-R0.5-M1	Brine	2	1	0.5	1
19	MO-P2-S2-R1-M1	Mineral Oil	1	2	1	1
20	MO-P0.5-S2-R0.5-M1	Mineral Oil	0.5	2	0.5	1
21	MO-P1-S2-R0.5-M1	Mineral Oil	1	2	0.5	1
22	MO-P2-S2-R0.5-M1	Mineral Oil	2	2	0.5	1
23	MO-P2-S0.035-R0.5-M1	Mineral Oil	2	0.035	0.5	1
24	MO-P2-S1-R0.5-M1	Mineral Oil	2	1	0.5	1
25	CO-P1-S2-R1-M1	Crude Oil	1	2	1	1
26	CO-P0.5-S2-R0.5-M1	Crude Oil	0.5	2	0.5	1
27	CO-P1-S2-R0.5-M1	Crude Oil	1	2	0.5	1
28	CO-P2-S2-R0.5-M1	Crude Oil	2	2	0.5	1
29	CO-P2-S0.035-R0.5-M1	Crude Oil	2	0.035	0.5	1
30	CO-P2-S1-R0.5-M1	Crude Oil	2	1	0.5	1

B – Brine

CO – Crude Oil

M- Matrix

MO – Mineral Oil

P – Polymer

R – Rate

S – Surfactant

W – Water

6.3 VISUALIZATION EXPERIMENTAL RESULTS

The purpose of this test is to visually understand the blocking mechanism of the CGA drilling fluid. Tests were conducted at different flow rates, polymer concentrations and surfactant concentrations for water, brine, mineral oil and crude oil as the saturation fluid. A test was also conducted to examine the effect of permeability.

6.3.1 *Effect of Injection Rate*

Figure 6-6 shows the effect of flow rate on the pressure drop across the micromodel for a water saturated micromodel. Fluid was injected at rates of 0.5 cc/min and 1 cc/min. The continuous increase in pressure along the CGA fluid injection indicates that the CGA fluid is blocking the pores of the micromodel. A slightly greater pressure rise is observed with the 0.5 cc/min injection rate than for the 1 cc/min injection rate. This indicates more effective pore blocking with the lower flow rate. For the 1 cc/min case, some instability occurred initially around 660 PV then recovered. An indication of instability is when there is a decrease in pressure while the fluid is being injected. The fluid is unstable because of coalescence of the air bubbles in the fluid. These periodic pressure fluctuations continued during the later part of the foam injection as shown in Figure 6-7.

A sudden increase in pressure drop was observed just after 559 and 989 PV (Pore Volumes), reaching the pressure limit of the cell. This was because the injection fluid was switched to water at 989 PV and 559 PV for the 1 cc/min and 0.5 cc/min injection rate cases, respectively. This is due to the difference in pressure between the inlet and outlet of the accumulator and a difference in pressure between the CGA fluid and the water that is being injected. Another factor controlling this is the difference in compressibility between water and the CGA fluid. Since water is an incompressible fluid, at the initial point when the fluid is switched to water, there is a greater pressure drop across the micromodel. Once the water reaches the micromodel, the CGA fluid is flushed out of the micromodel and the pressure drop then decreases. Figure 6-8 shows a zoomed version of the later half of the 0.5 cc/min run illustrated in Figure 6-6. From Figure 6-8 it can be seen that after the water has reached the cell, there were still periodic pressure increases (572 PV, 588 PV and 600 PV) before a constant pressure was reached. As the water injection continues, the pressure drop stabilizes and reaches near to the initial water injection pressure level, indicating that all of the CGA fluid is

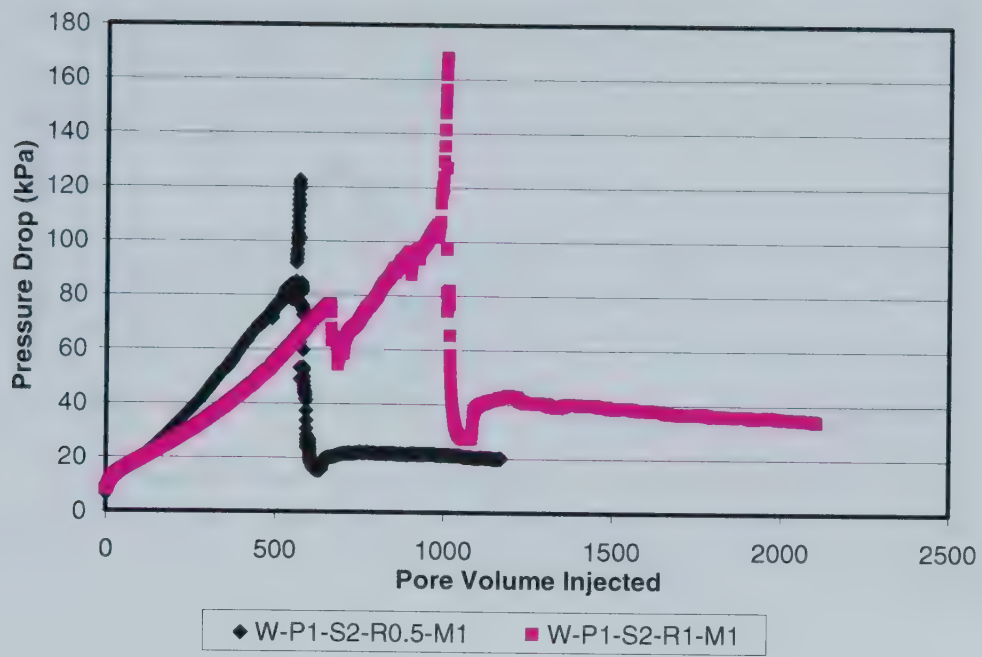


Figure 6-6: Pressure data for aphron injection at different flow rates.

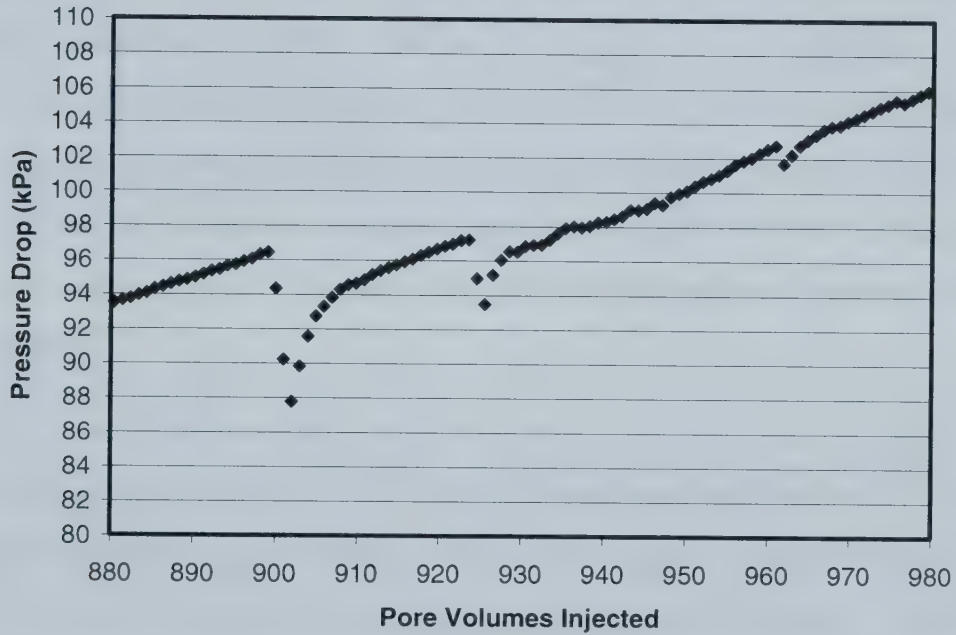


Figure 6-7: Later stages of CGA Fluid injection for experiment W-P1-S2-R1-M1.

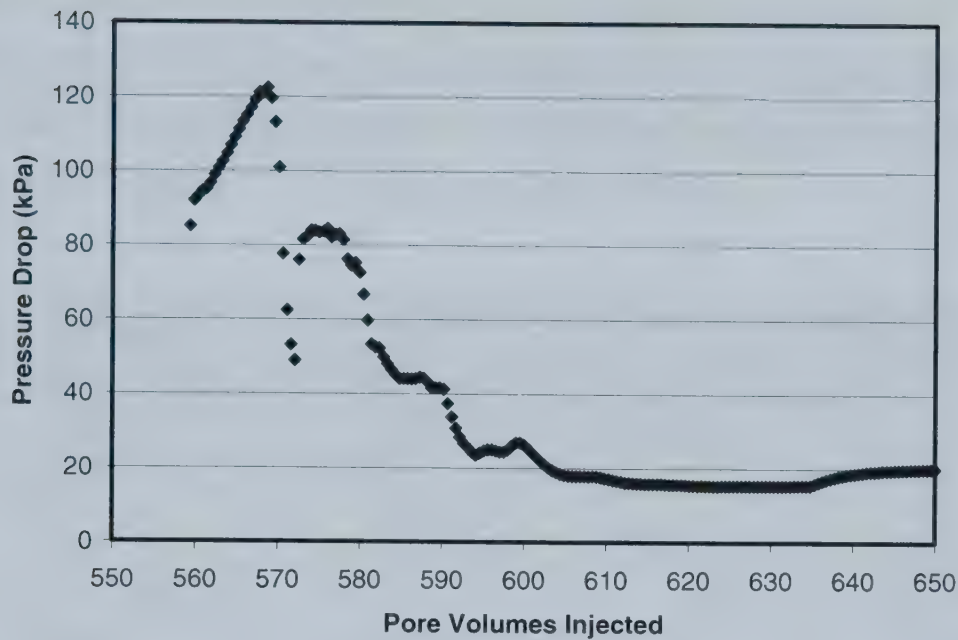


Figure 6-8: Water injection for experiment W-P1-S2-R0.5-M1.

removed from the micromodel. For the 1cc/min case, 15 PV were injected from the point of which the injection fluid was switched to water to the point of when the pressure first started to decrease. Another 100 PV were needed to return the cell to the original pressure drop before CGA injection. For the 0.5 cc/min case, from the point of which the injection fluid was switched to water to the point of pressure decrease took 9 PV and to the point of the original pressure drop was another 50PV.

Images taken during the W-P1-S2-R1-M1 experiment are shown in Figure 6-9. The images show the cell initially saturated with water, the progression of foam into the cell and then the removal of the foam via water injection. It can be seen that air initially invades the cell at 8.3 kPa (1 PV) and at 10 kPa (8.8 PV) as there is some foam present in the cell and the pressure required to inject the CGA fluid into the micromodel has been reached. The amount of CGAs increases as the pressure builds up to 30 kPa (250 PV). At this point, the CGAs are fully flowing through the cell. Before the water injection at 103.4 kPa and 966 PV, the CGAs is

moving at a fast pace through the cell. This is evident by the blurred flow paths. Following the water injection at approximately 1000 PV, the fast pace foam is still evident within the cell at 1001 PV (47.6 kPa) but has been almost eliminated by 2073 PV and the pressure has dropped back to 35 kPa.

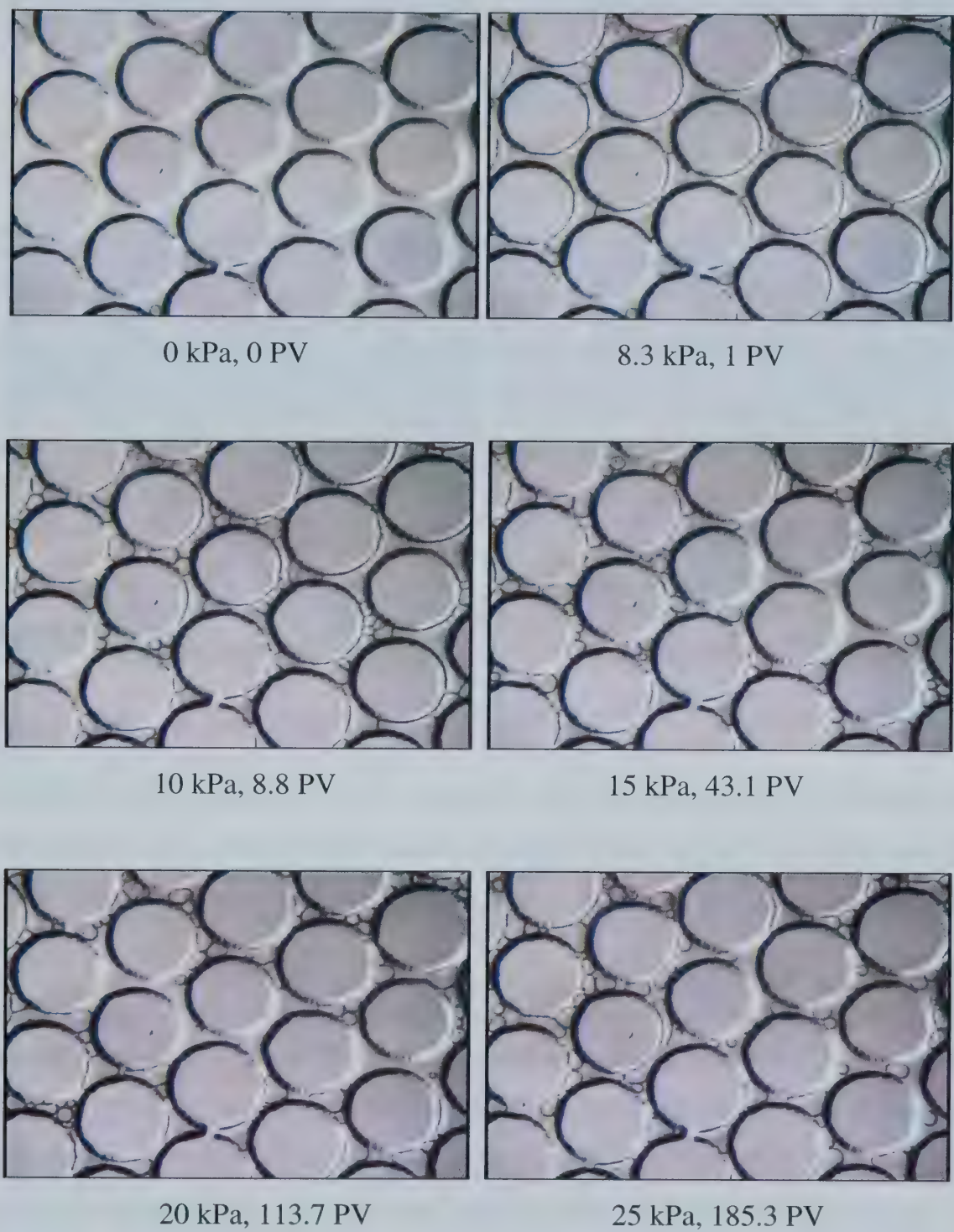


Figure 6-9: Images of aphron flow through the microcell for W-P1-S2-R1-M1. Images taken at 1.6 x magnification.

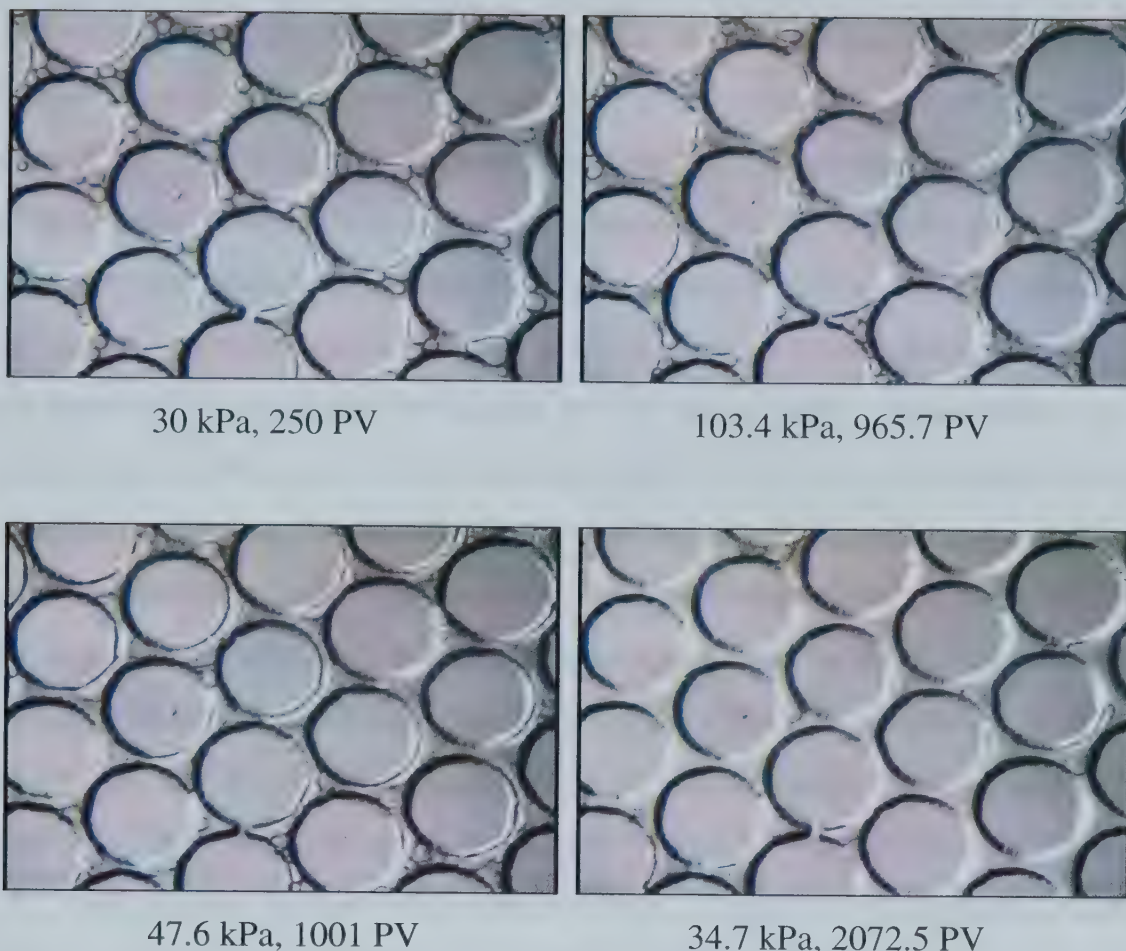


Figure 6-9: Cont.

6.3.1.1 Effect of Pore Fluid Type

The effect of flow rate for a brine saturated micromodel is given in Figure 6-10. It shows that the increase in pressure is slightly greater for the 1 cc/min case than for the 0.5 cc/min case indicating that a higher flow rate give a greater pressure drop.

For the mineral oil case (Figure 6-11) there is a slight difference in the initial injection pressure, 76 kPa for 1 cc/min and 101 kPa for 0.5 cc/min but the slope of both curves is similar. This difference in injection pressure may be due to the difference in flow rate. The injection pressure is much greater for the mineral oil (76 kPa) case than for the water (6 kPa) or brine cases (6 kPa). This could be due to the large difference in viscosity between the mineral oil and water. Since the

mineral oil is more viscous than water, there is less injectivity in the mineral oil case and a greater pressure needs to be exerted in order for the CGA fluid to enter the cell. Another consequence of viscosity is that after the injection fluid was switch back to mineral oil (approximately 200 PV) the pressure continued to rise to the maximum capacity of the micromodel and did not decrease as it did with the water and brine cases. The differential pressure across the micromodel is expected to be much greater than 250 kPa at 0.5 cc/min when injecting mineral oil and therefore exceeds the limitations of the micromodel. Nevertheless, it is evident that it takes a greater pressure to inject CGA's into a cell saturated with mineral oil (between 76 and 101 kPa) than it does when the cell is saturated with water or brine (less than 10 kPa). As well, with a mineral oil saturated cell, the effective permeability of the cell to an aqueous fluid is less. Therefore, the pressure needed to inject the aqueous fluid into the cell is greater. It is also evident that the CGA fluid is not stable for the mineral oil case at the beginning of injection. There were decreases in pressure during the experiment at less than 50 PV. This was not the case with water or brine. It may be due to the fact that it takes a longer time to reach the pressure needed to inject the CGA into the micromodel for mineral oil than it does for water (approximately 10 times longer) and therefore the initial fluid injected is less stable and more prone to coalescence than the fluid that was injected in the water and brine cases.

Figure 6-12 illustrates the rise in pressure with a crude oil saturated micromodel. The rate of pressure increase is similar for both the 0.5 cc/min and the 1 cc/min CGA fluid injection rates. As was the case with the mineral oil saturated micromodel, the initial injection pressure was greater than the injection pressure for water and brine. This can also be due to the relatively higher viscosity of the saturation fluid as well as a low effective permeability. The injection pressure was 35 kPa for the 0.5 cc/min of CGA fluid injection rate and 30 kPa for the 1 cc/min of CGA fluid injection rate. As with the mineral oil case, once the injection fluid was switched back to crude oil (around 450 PV), the pressure continued to rise and exceeded the limitations of the micromodel. This is because

at the set flow rate, the pressure drop of the 7 cP crude oil exceeds the pressure of cell.

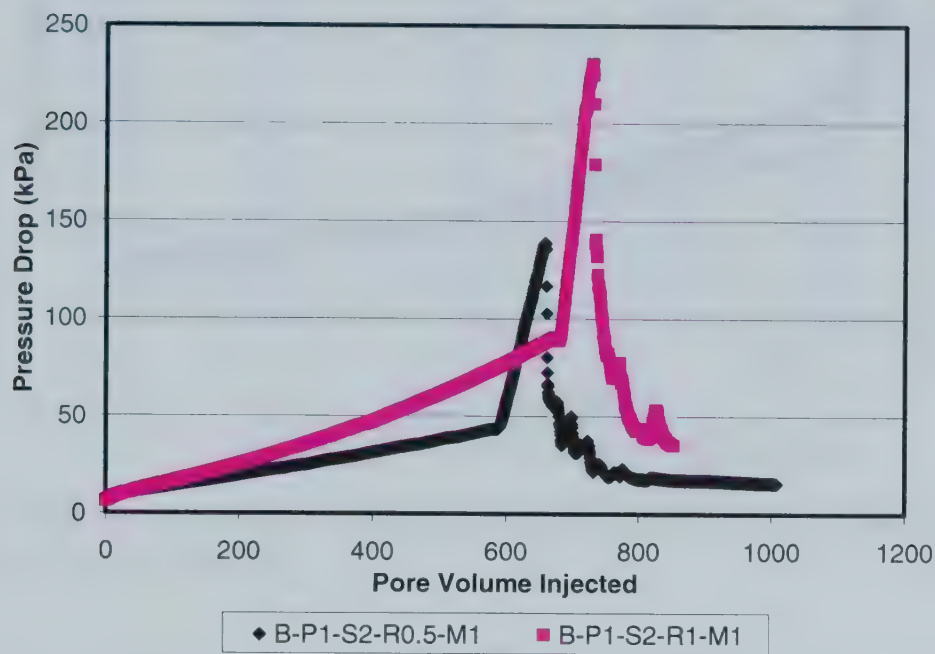


Figure 6-10: Pressure data for aphron injection at different flow rates with brine as the saturation fluid.

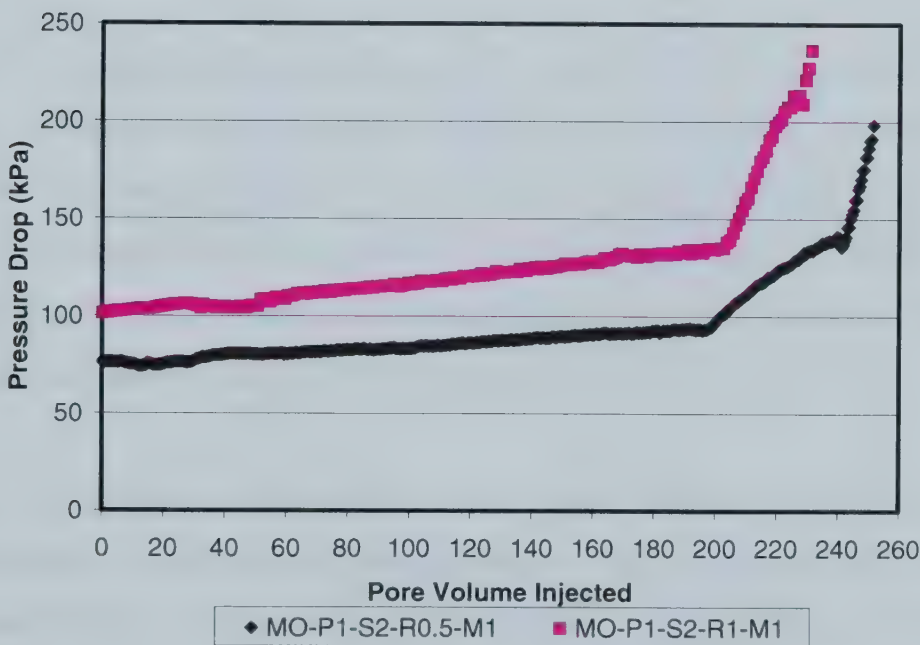


Figure 6-11: Pressure data for aphron injection at different flow rates with mineral oil as the saturation fluid.

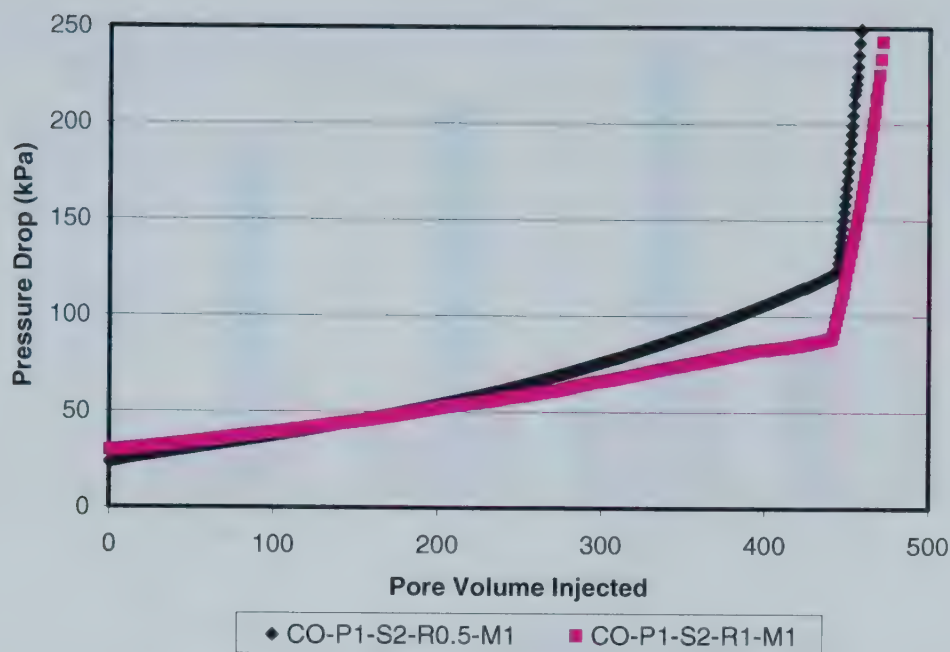


Figure 6-12: Pressure data for aphron injection at different flow rates with crude oil as the saturation fluid.

Figure 6-13 and Figure 6-14 compares the injection pressure required for CGA fluid injection into a micromodel saturated by water, brine, mineral oil and crude oil at injection rates of 1 cc/min and 0.5 cc/min. Both figures show that the CGA fluid injection pressure increases as the viscosity of saturating fluid increases.

Table 6-4 compares the initial injection pressure for all experiments at injection rates of 1 cc/min and 0.5 cc/min. It shows that as the flow rate increases, the injection pressure also increases for the crude oil and mineral oil as the saturating fluids. The same trend was not clearly observed when water and brine were used as saturating fluid. The discrepancy may be due to the insensitivity of the pressure transducer since the pressure needed to inject the fluid is low.

Table 6-5 summarizes the injection time spent before the first instability of injected fluid was seen for all experiments. The instability of CGA fluid was indicated by 1% or more decrease in injection pressure during the CGA fluid injection. The CGA fluid was the least stable during the experiment when

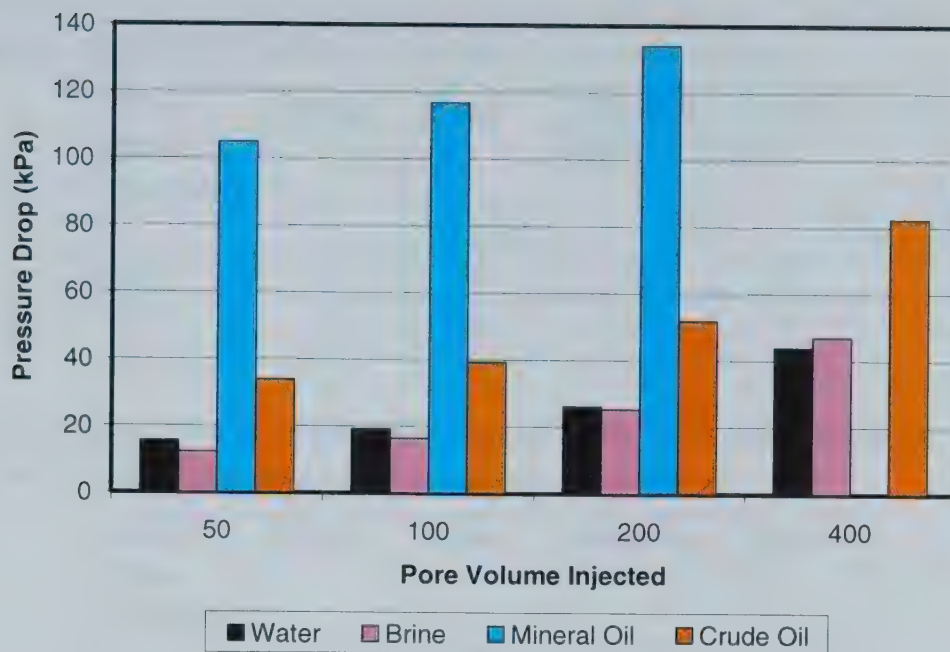


Figure 6-13: Comparison of pressure data for aphron injection with different fluid types at 1 lb/bbl XG, 2 lb/bbl DDBS and 1 cc/min.

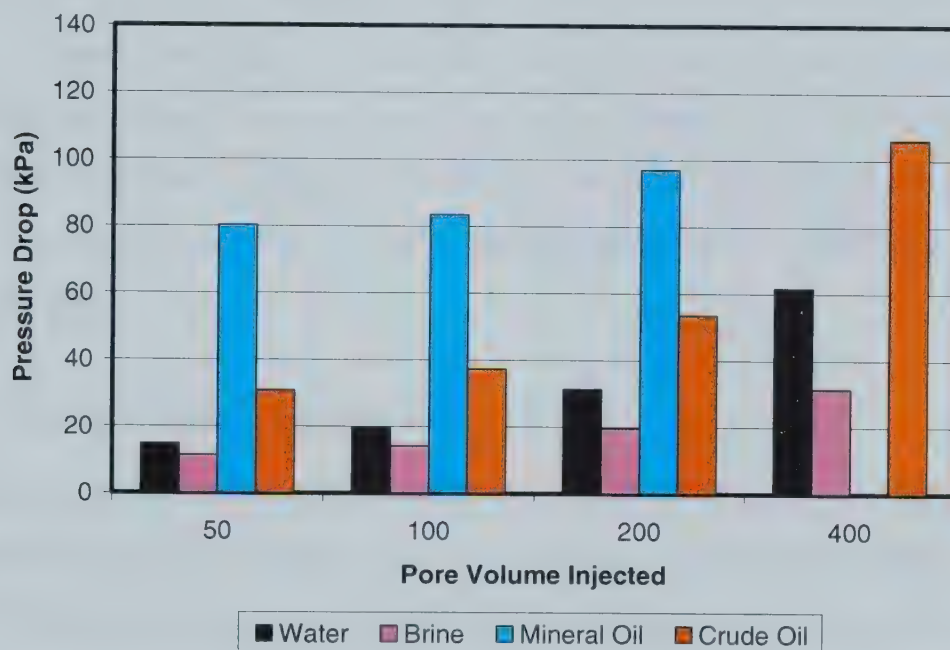


Figure 6-14: Comparison of pressure data for aphron injection with different fluid types at 1 lb/bbl XG, 2 lb/bbl DDBS and 0.5 cc/min.

Table 6-4: Comparison of pressure required for injection of CGA Fluid into a micromodel saturated by water, brine, mineral oil and crude oil

Flow Rate (cc/min)	Water	Brine	Mineral Oil	Crude Oil
kPa				
0.5	6	6	76	24
1	8	6	101	30

Table 6-5: Comparison of initial instability of CGA fluid injected into a micromodel saturated by water, brine, mineral oil and crude oil

Flow Rate (cc/min)	Water	Brine	Mineral Oil	Crude Oil
PV				
0.5	358	660	7	>440
1	661	673	28	>440

mineral oil was used as saturating fluid. This is mainly due to the longer time needed to inject the fluid into the cell. The CGA fluid injected into the cell saturated with crude oil was stable for the entire duration of the experiment (440 PV). The CGA fluid injected into both the water and brine saturated cells was stable for greater than 600 PV with one exception (0.5 cc/min with a water saturated cell).

6.3.2 Effect of Polymer Concentration

Figure 6-15 shows that as the polymer concentration is increased, the pressure drop increased with pore volume injected. The effect is not very evident between 0.1 and 2 lb/bbl polymer concentrations but become more obvious as the polymer concentration is increased above 2 lb/bbl. This shows the effect of the injection fluid viscosity on the pressure drop. The more viscous the injection fluid becomes, the greater the pressure drop. As well, Figure 6-15 shows the effect polymer concentration on the stability of the aphronized fluid. The time at which the aphronized fluid becomes unstable, increases with an increase in XG concentration. It shows that as the polymer concentration is increased, the

pressure rise with pore volume injected also increases. The effect is not very evident between 0.1 and 2 lb/bbl but becomes more obvious as the polymer concentration is increased above 2 lb/bbl. This is an indication of the effect of viscosity on the injection fluid. The more viscous the injection fluid becomes, the greater the pressure rise. The effect of polymer concentration on the pressure drop is more significant at low surfactant concentration as shown in Figure 6-16. This is due to the fact that as the amount of surfactant is decreased, there are less CGA's in the system and the effect of polymer viscosity is greater.

Figure 6-17 shows the instability of the low polymer concentration cases (0.1 and 0.5 lb/bbl). Pressure drops were evident at 100 and 400 PV for the 0.1 and 0.5 lb/bbl case respectively indicating that at these polymer concentrations, a stable CGA fluid cannot be generated for an extended period of time. Therefore, the polymer concentration of the CGA fluid should be at least 0.5 lb/bbl or greater. From Figure 6-18, the 2 lb/bbl case did not show any instability and pressure continued to rise for the length of the test. Although the pressure continued to rise, the CGA injection was terminated at 125 kPa (685 PV) due to the inability of the micromodel to withstand great pressures. Once the injection fluid was switched to water, the pressure rose to greater than 150 kPa. Therefore the maximum pressure that the flow would reach or the pressure at which the foam became unstable at this particular flow rate could not be determined.

Images taken during the CGA injection at a rate of 0.5 cc/min and a 0.5 lb/bbl polymer concentration (W-P0.5-S2-R0.5-M1) are shown in Figure 6-19. The images show air invading the cell at 5.5 kPa. A small amount of aphron bubbles are evident at 10 kPa and the aphron bubble presence increases as pressure increases to 30 kPa. At 36.2 kPa and 391 PV, the aphrons present in the cell are no longer individual and circular but have coarsened and are no longer stable.

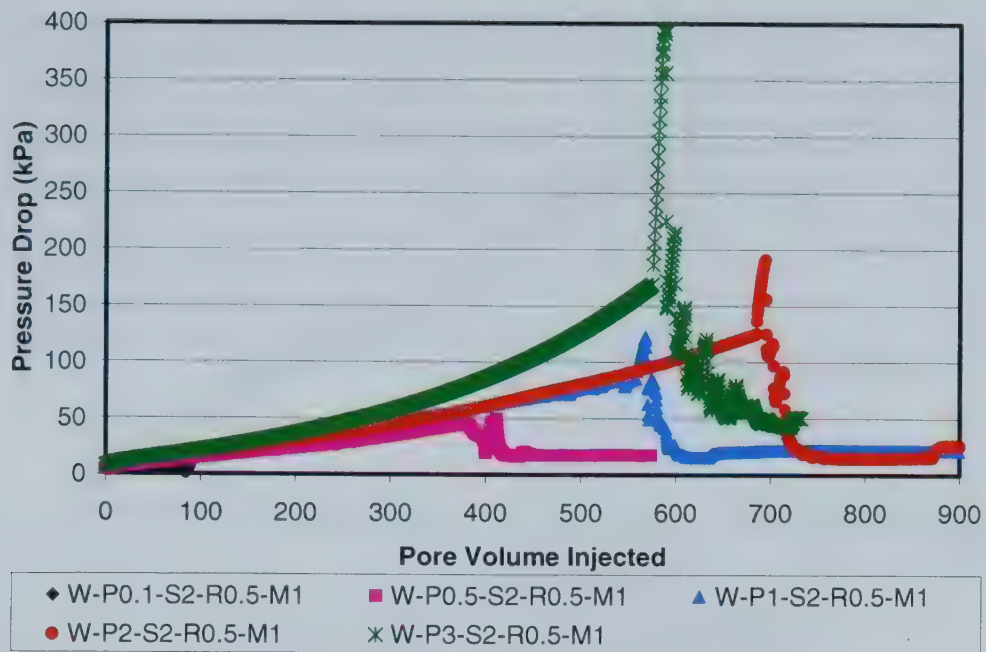


Figure 6-15: Pressure data for CGA injection for different concentrations of XG with a water saturated micromodel.

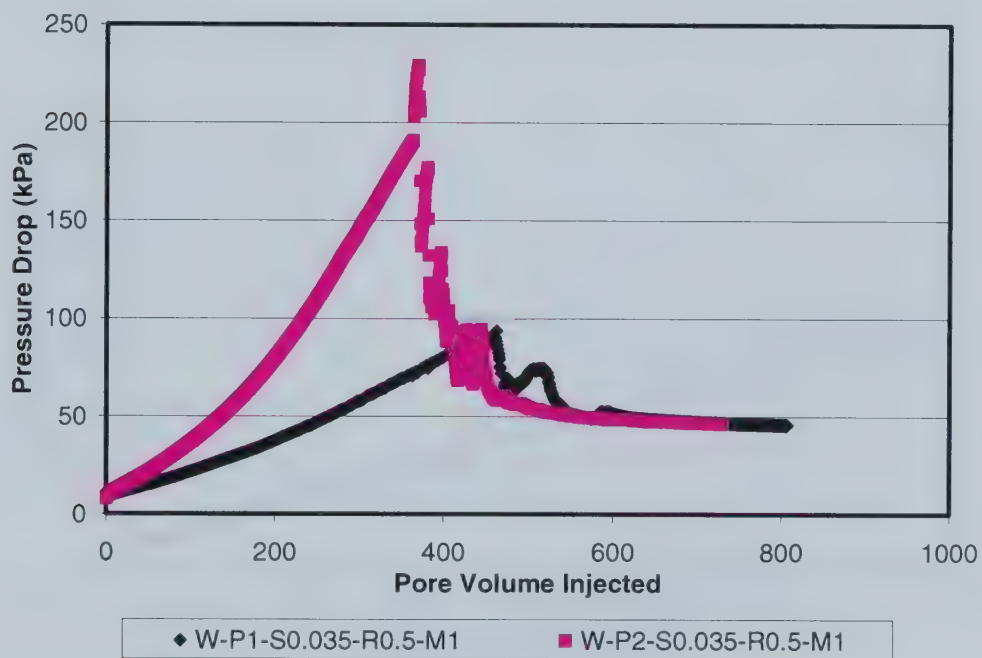


Figure 6-16: Pressure data for aphron injection with a water saturated micromodel for different concentrations of polymer.

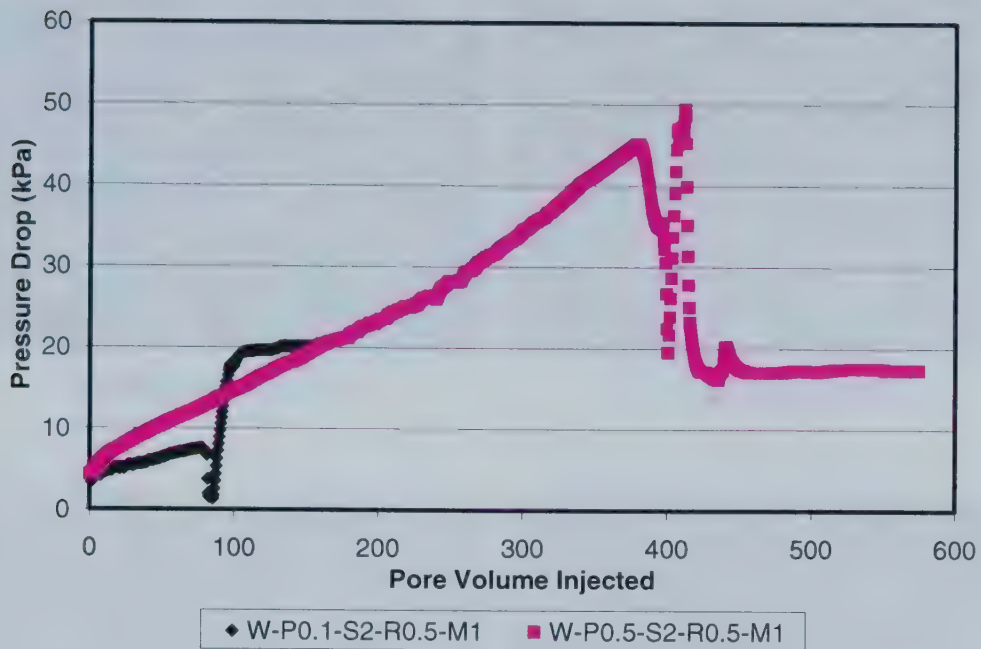


Figure 6-17: Pressure data for CGA fluid injection for low XG concentration.

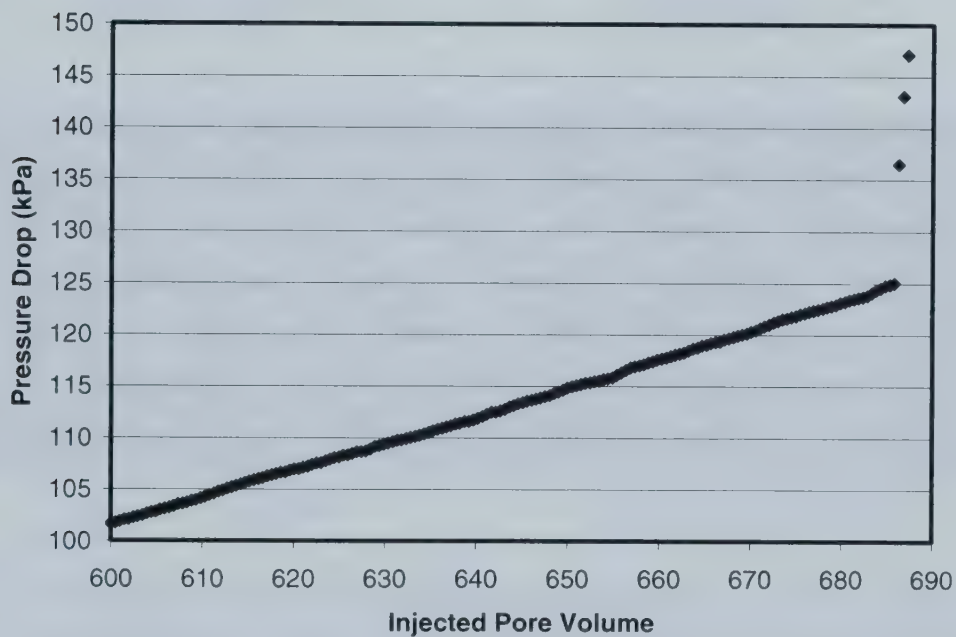
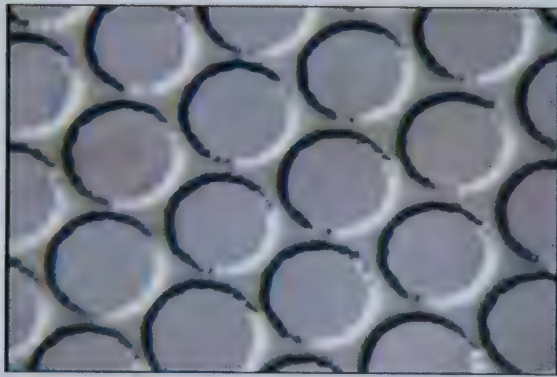
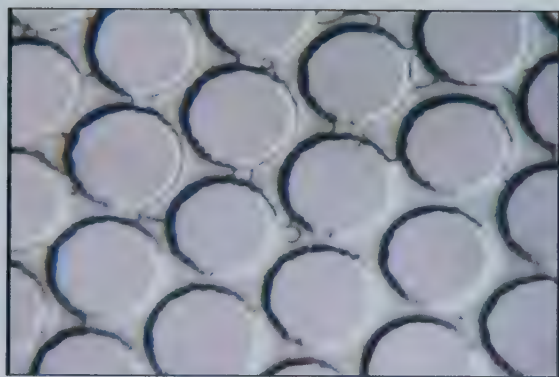


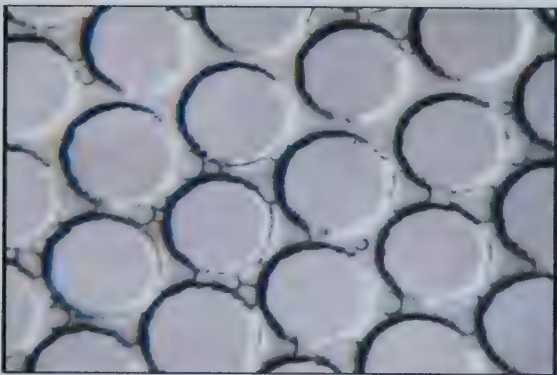
Figure 6-18: Later stages of CGA fluid injection for 2 lb/bbl polymer (W-P2-S2-R0.5-M1).



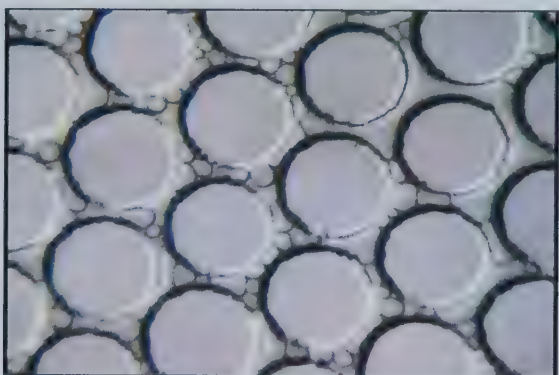
0 kPa, 0PV



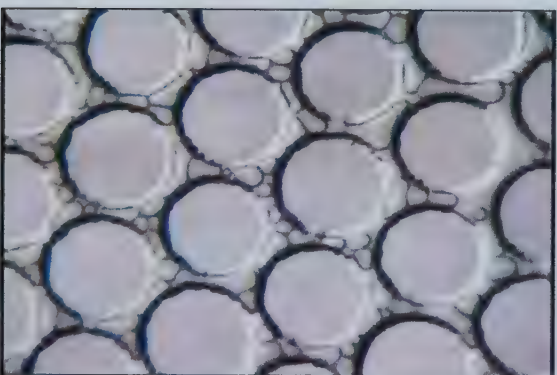
5.5 kPa, 5.9PV



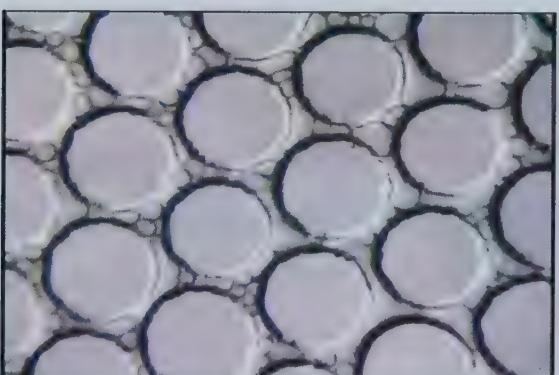
10 kPa, 45.6 PV



15 kPa, 104.4 PV



20 kPa, 158.8 PV



25 kPa, 222.5 PV

Figure 6-19: Images of CGA fluid flow through the micromodel for an injection rate of 0.5 cc/min and a 0.5 lb/bbl polymer concentration (W-P0.5-S2-R0.5-M1). Images taken at 1.6 x magnification.

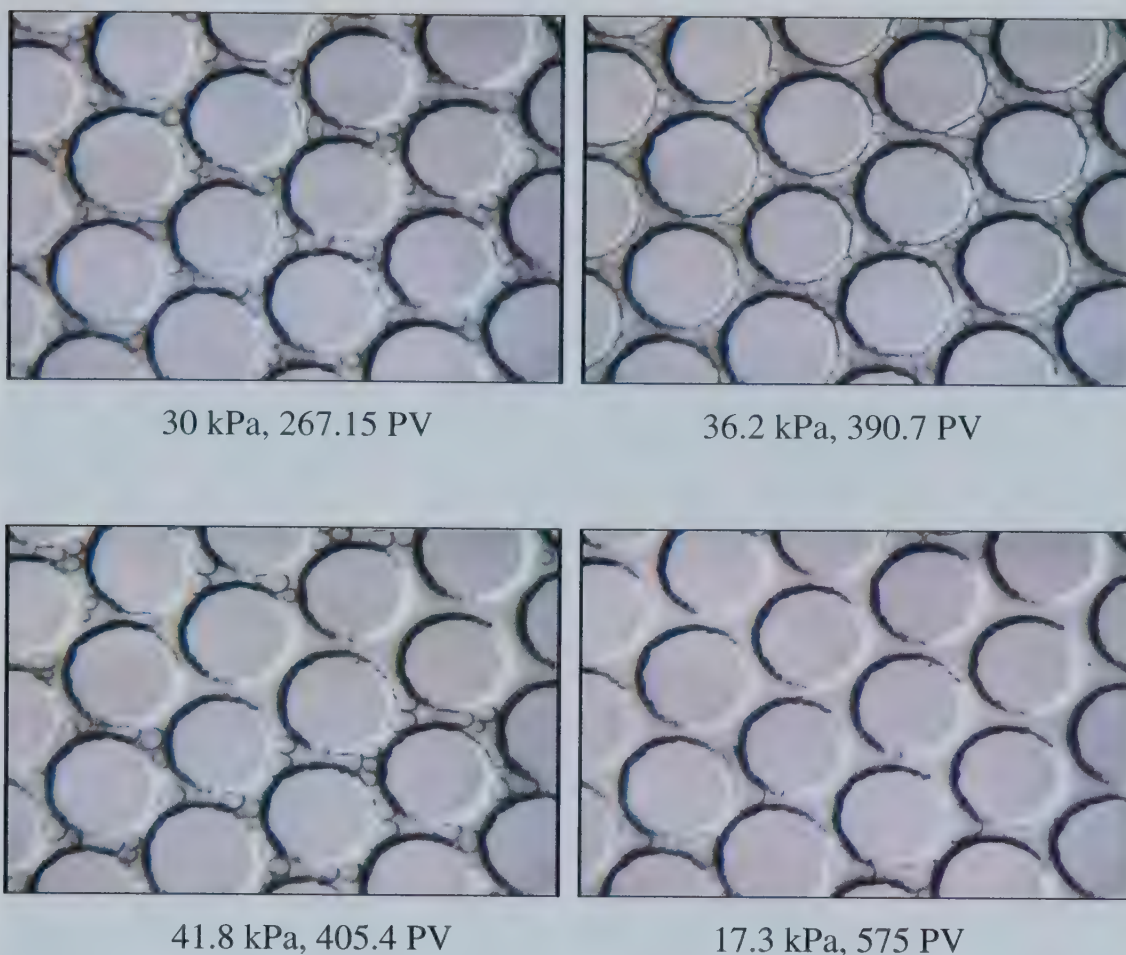
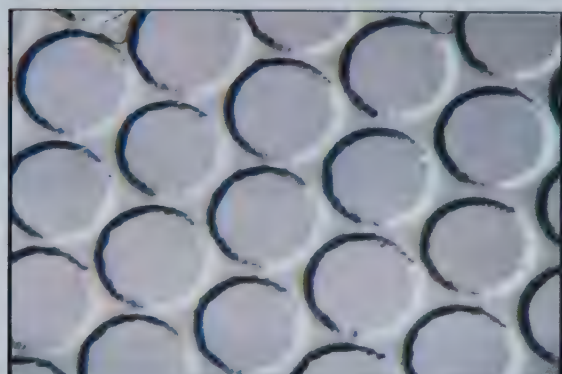


Figure 6-19: Continued

Figure 6-20 illustrates the images of the CGA fluid flow with 2 lb/bbl polymer (XG) concentration and a flow rate of 0.5 cc/min (W-P2-S2-R0.5-M1). The figure shows the bubbles do not invade the cell until the pressure is between 10 and 15 kPa and does not totally invade the cell until after 25 kPa. For the water saturated cells, all runs showed that the CGAs enter the cell at injection pressures of 10 to 20 kPa. Figure 6-21 shows that after injecting similar pore volumes of CGA fluid, the amount of microbubbles in the micromodel decreases as the polymer concentration increases from 2 to 3 lb/bbl. Since the shear rate used for mixing the CGA fluids and surfactant concentrations are fixed for both fluids, the viscosity of the base fluid would be the only factor which could affect the amount of air entrainment during CGA generation. Since there are less microbubbles observed in the micromodel when CGA fluid with high polymer concentration (3 lb/bbl) is injected, it can be assumed that it is more difficult to generate CGA's as

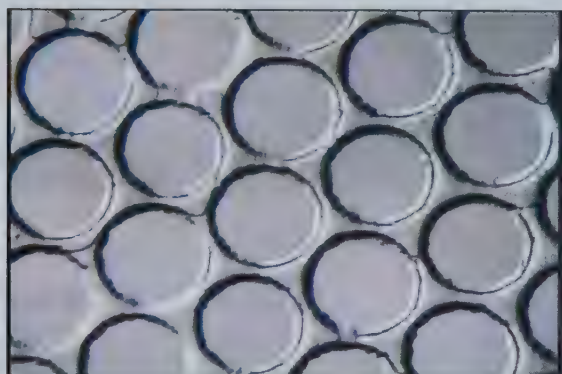
the viscosity of the base fluid increases. Therefore, a polymer concentration of greater than 2 lb/bbl is not desirable since it impedes the generation of CGA's.



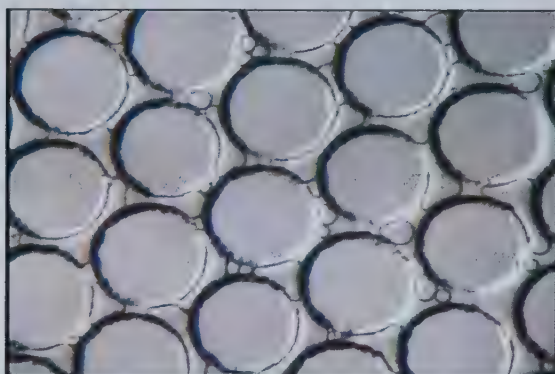
0 kPa, 0PV



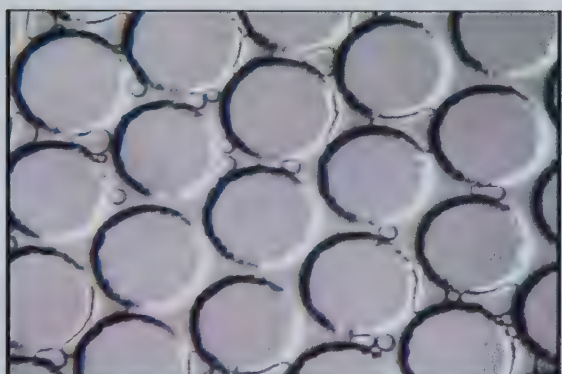
5.7 kPa, 0.5 PV



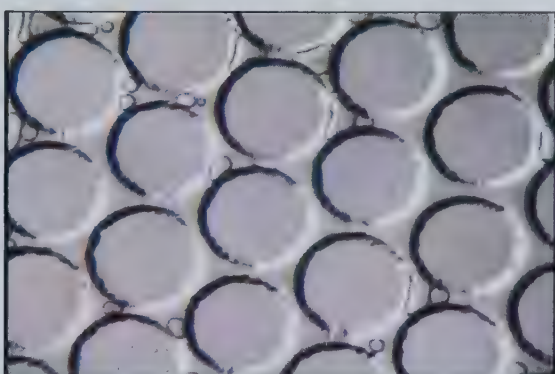
10 kPa, 20.1 PV



15 kPa, 58.3 PV

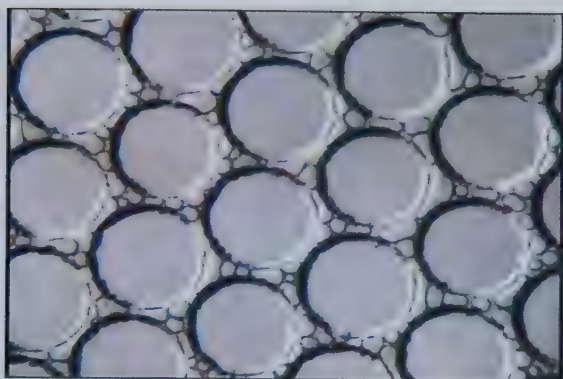


20 kPa, 107.4PV

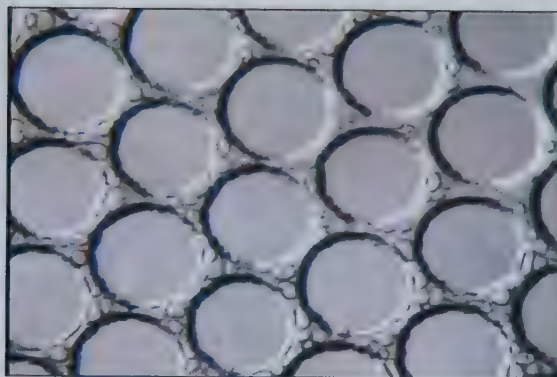


25 kPa, 155.9 PV

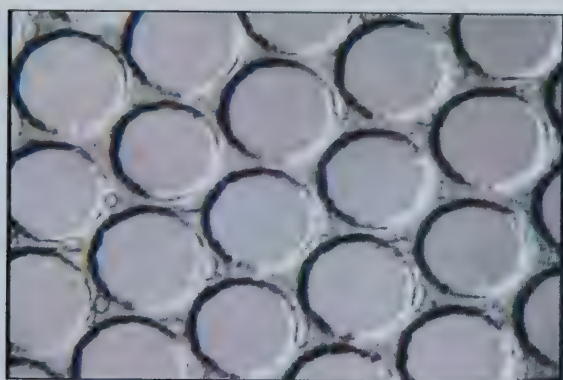
Figure 6-20: Images of CGA fluid flow through the micromodel for an injection rate of 0.5 cc/min and a 2 lb/bbl polymer concentration (W-P2-S2-R0.5-M1). Images taken at 1.6 x magnification.



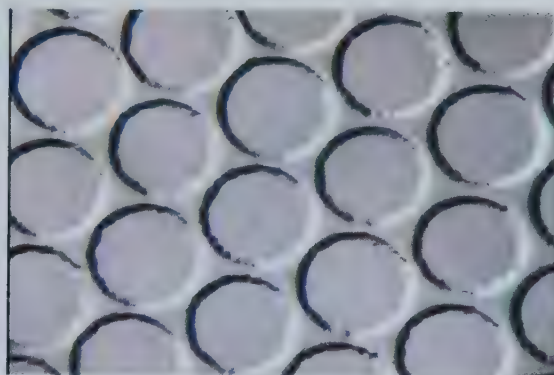
30 kPa, 199.5 PV



124 kPa, 684.3 PV



143 kPa, 686.8 PV



23.6 kPa, 994.6

Figure 6-20: Continued

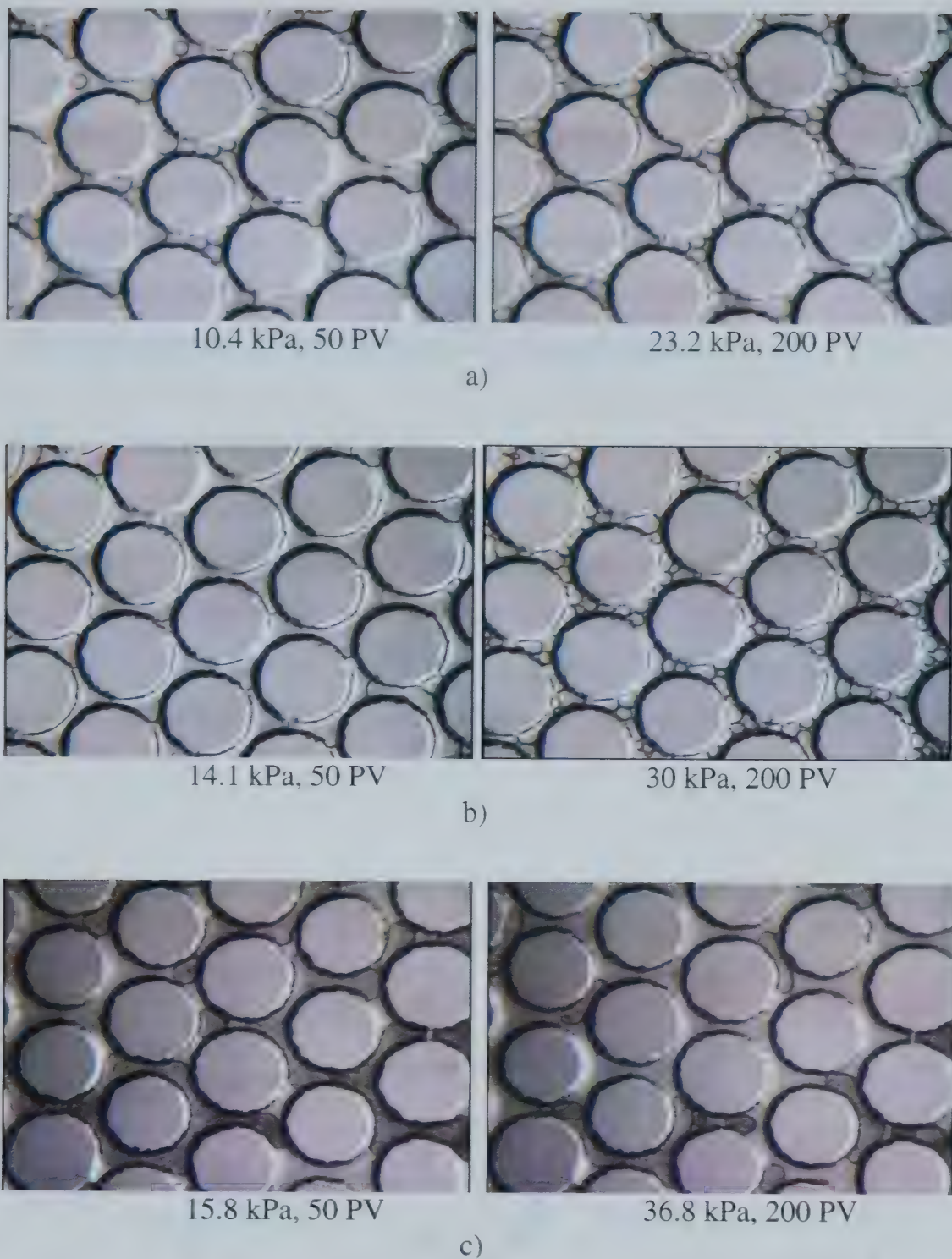


Figure 6-21: Images of CGA injection with a water saturated micromodel at a) 0.5 lb/bbl polymer concentration, W-P0.5-S2-R0.5-M1. b) 2 lb/bbl polymer concentration, W-P2-S2-R0.5-M1 and c) 3 lb/bbl polymer concentration, W-P0.5-S2-R0.5-M1

As the polymer concentration decreases, the stability of the CGA fluid is reduced. It is, therefore, important to have a high enough polymer concentration (greater

than 0.1 lb/bbl) that will create a stable bubble for an extended period of time. However, the greater the polymer concentration, the more difficult it becomes to generate CGA's. Less CGA's and more polymer in the system may cause more formation damage. Therefore, it is important to determine a critical polymer concentration which will give the optimum CGA formulation. For the system used in this study, the maximum polymer concentration is 2 lb/bbl and the minimum polymer concentration is more than 0.1 lb/bbl.

6.3.2.1 Effect of Pore Fluid Type

Figure 6-22 indicates that as the polymer concentration increases, CGA fluid injection pressure also increases when the micromodel is saturated with mineral oil. This increase in injection pressure is due to the increasing viscosity of the aphron fluid with the addition of more polymer. The injection pressure for fluid with 0.5 lb/bbl XG is 63 kPa and for fluid with 2 lb/bbl XG is 134 kPa.

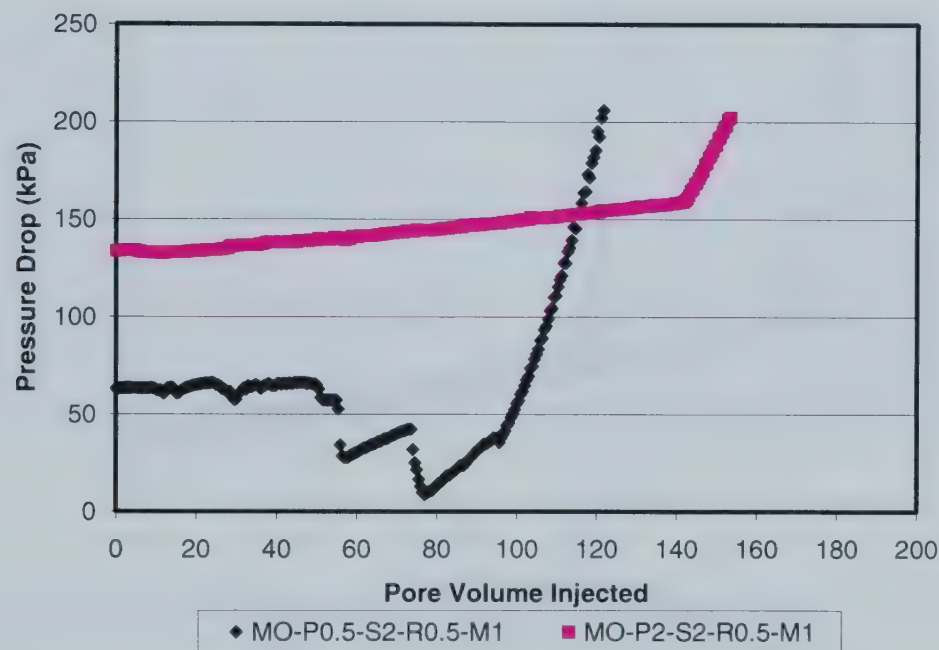


Figure 6-22: Pressure data for CGA fluid injection with a mineral oil saturated micromodel for different concentrations of polymer (XG).

The instability of the fluid with low polymer concentrations (0.1 lb/bbl, 0.5 lb/bbl) is evident in Figure 6-22 as there is not a steady increase in pressure drop in the cell with continuous CGA fluid injection. For the CGA fluid prepared with 0.5 lb/bbl XG concentration, there is a decrease in pressure drop between the injected CGA fluid volumes of 15 to 20 PV, 25 to 35 PV and after 50 PV. These decreases in pressure drop are indication of CGA fluid instability.

The effect of polymer concentration on the pressure drop across the micromodel saturated with crude oil is shown in Figure 6-23 to Figure 6-25. Pressure increases gradually as more CGA fluid is injected (Figure 6-23). The amount of crude oil displaced from the micromodel is noticeably different for two fluids shown in Figure 6-24 and Figure 6-25. After injecting about 80 PV of CGA fluid with 2 lb/bbl polymer, there was very little crude oil left in the cell (Figure 6-25). Since the etched glass micromodel is water wet by nature, once the CGA fluid enters the micromodel it effectively forces the non-wetting fluid out of the cell.

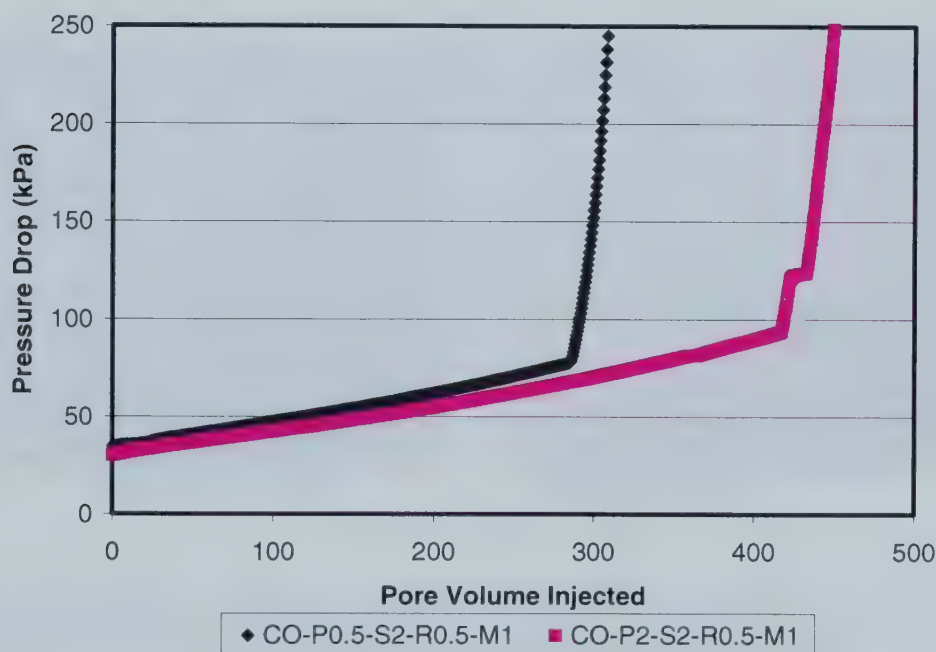


Figure 6-23: Pressure data for CGA fluid injection with a crude oil saturated micromodel for different concentrations of polymer.

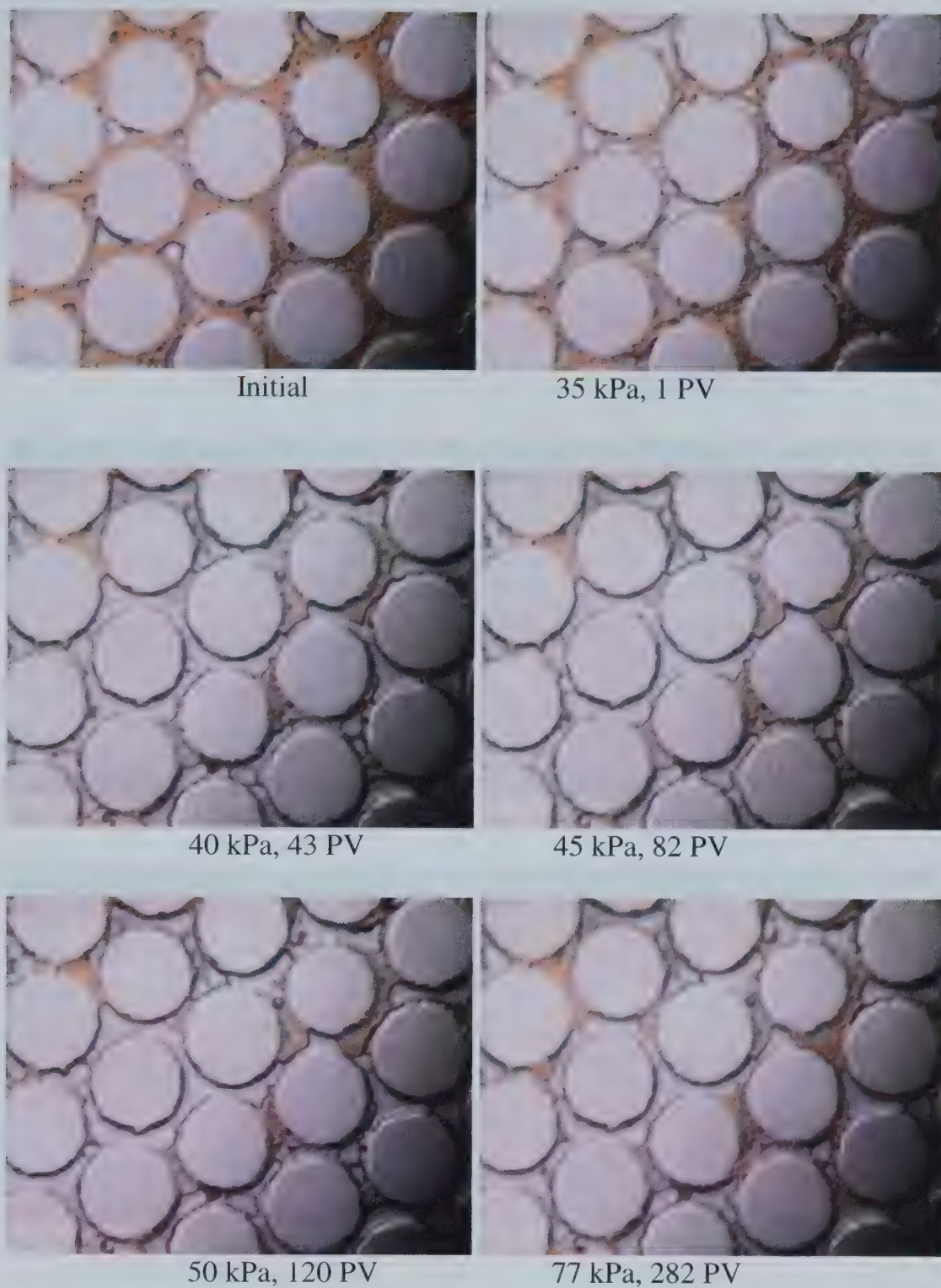


Figure 6-24: Images of CGA fluid flow through the micromodel with a flow rate of 0.5 cc/min and a polymer concentration of 2 lb/bbl (CO-P2-S2-R0.5-M1). Images taken at 1.6 x magnification.

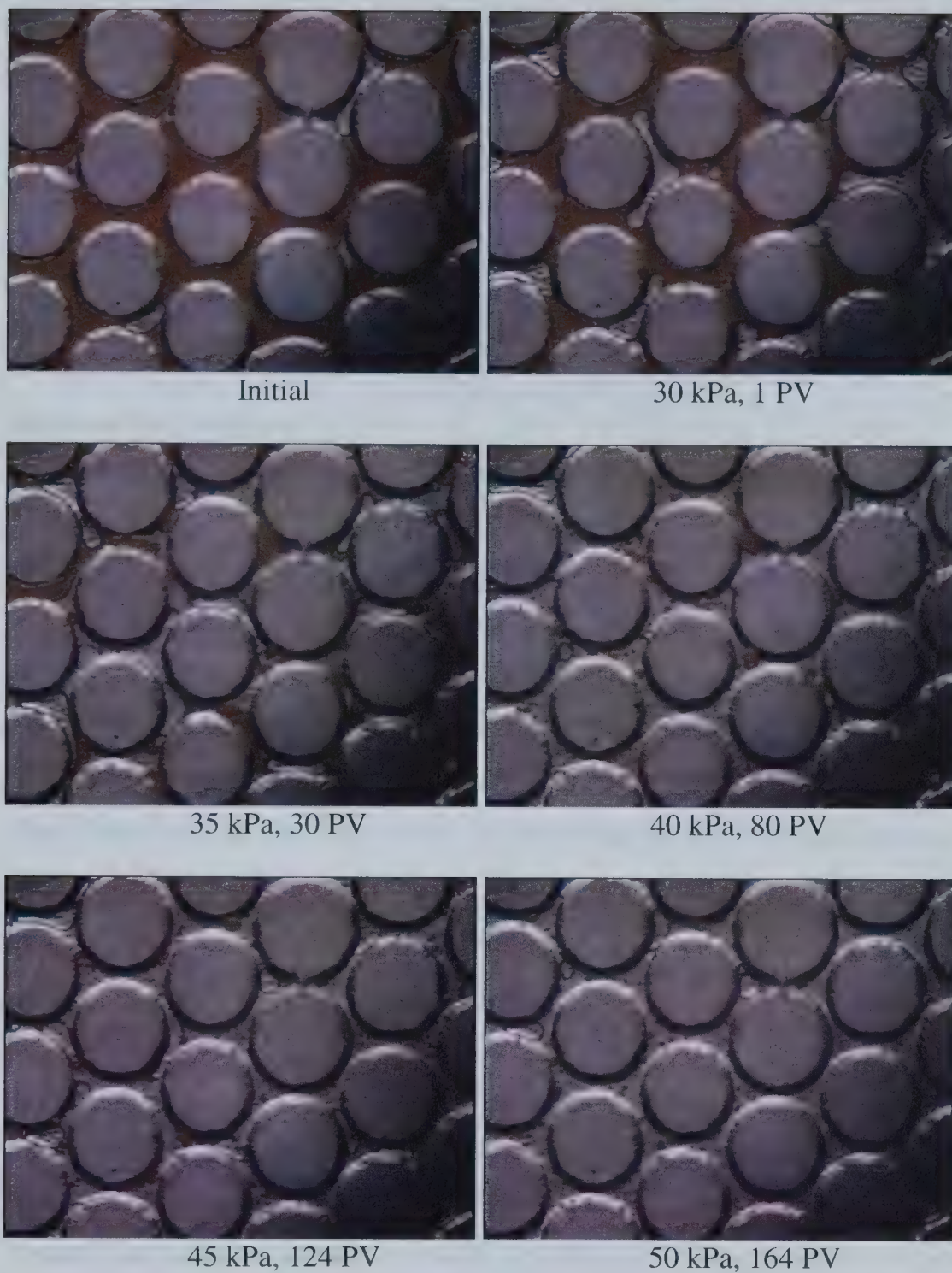
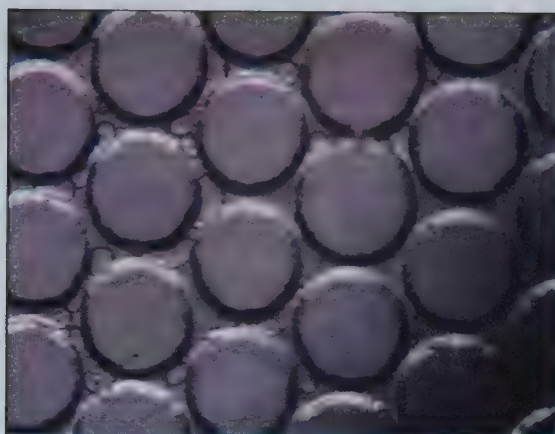


Figure 6-25: Images of CGA fluid flow through the micromodel with a flow rate of 0.5 cc/min and a polymer concentration of 0.5 lb/bbl (CO-P0.5-S2-R0.5-M1). Images taken at 1.6 x magnification.



93 kPa, 413 PV

Figure 6-25 Continued

This is the case for all crude oil experiments with the exception of the experiment with the CGA fluid composed of 0.5 lb/bbl of polymer (Figure 6-24). During this test, the images indicate that there was little flow through the selected viewing area of the cell as the pressure increased and that the crude oil was not displaced out of the cell. Since this fluid is one of the lowest viscosity fluid studied, it is more likely to break down and have less of a piston-like displacement than the other fluids studied. As well, it was observed during the test some crude oil was bypassed and left in the injection line which was positively displaced through the cell by the CGA fluid in all other cases.

Figure 6-26 and Figure 6-27 illustrate how the pressure required for injecting various CGA fluids (a-with 0.5 lb/bbl polymer , b- with 2lb/bbl polymer) into a micromodel saturated with water, brine, mineral oil, and crude oil changes as a function of injection (pore) volumes. Both figures show that the injection pressure increases at a faster rate with an increase in saturating fluid viscosity. The mineral oil data is absent at 200 and 400 PV in Figure 6-27 because the injection pressure exceeded the limitations of the micromodel before 200 PV.

Table 6-6 summarizes the injection pressures for all experiments comparing the effect of polymer concentration. Higher injection pressure is recorded as the polymer concentration of the CGA fluid is increased when mineral oil was used as

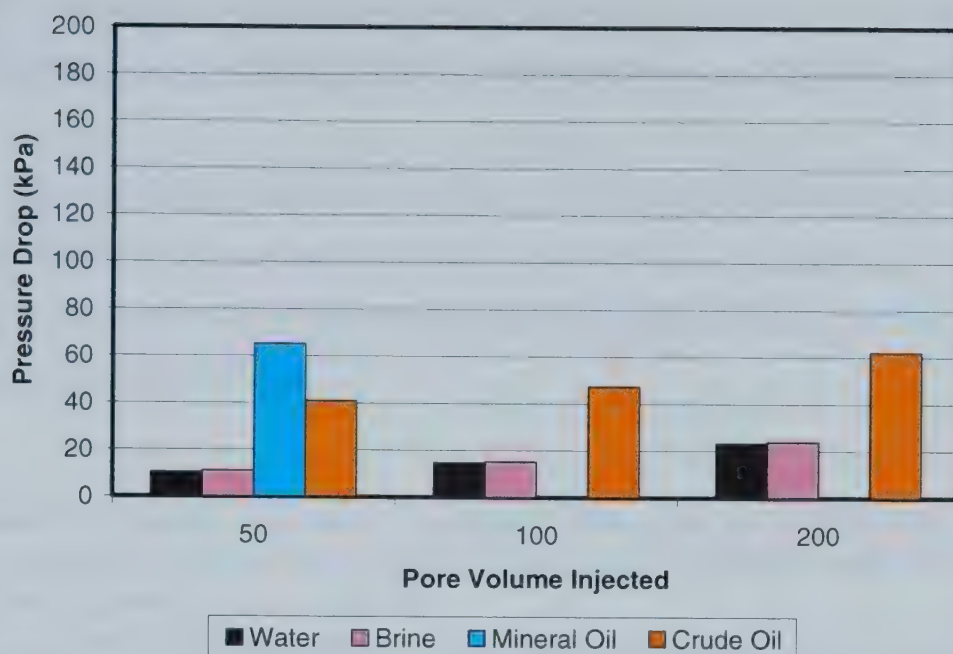


Figure 6-26: Comparison of pressure data for CGA fluid injection with different fluid types - 0.5 lb/bbl polymer, 2 lb/bbl surfactant and a flow rate of 0.5 cc/min.

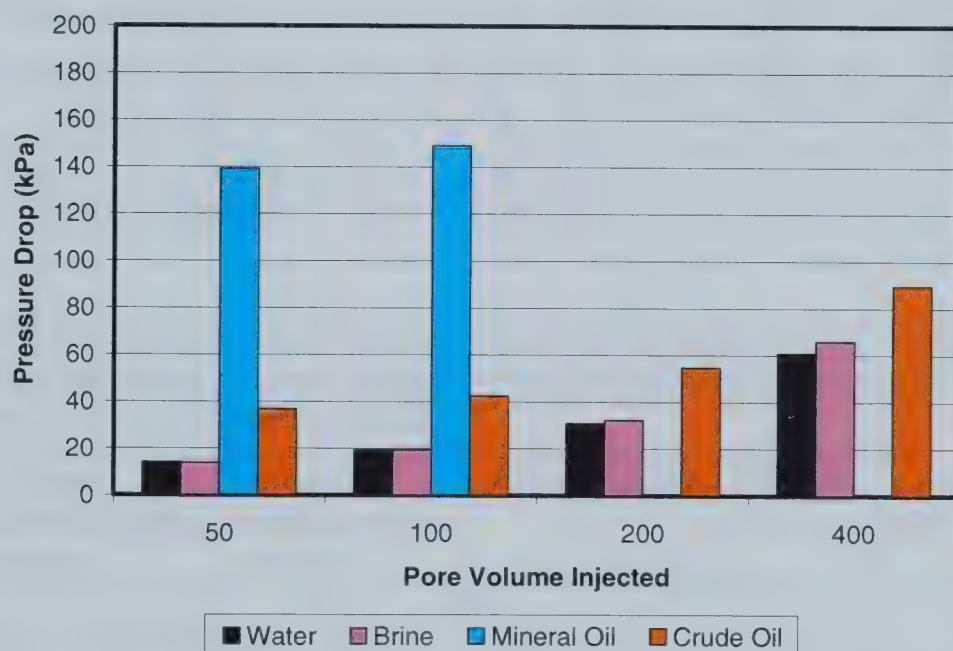


Figure 6-27: Comparison of pressure data for CGA injection with different fluid types with 2 lb/bbl polymer, 2 lb/bbl surfactant and a flow rate of 0.5 cc/min

the saturating fluid. For all other experiments, the injection pressure did not change significantly with the increasing polymer concentration. It can be assumed that the pressures in Table 6-6 are the pressures needed for a 60 μ m

CGA to enter into a 50 μm pore (pore diameter for matrix 1). 60 μm is the average bubble size of a stable CGA (1-3 lb/bbl polymer and 2 lb/bbl surfactant)

Table 6-7 shows the pore volume injected until an initial instability occurred for all CGA fluids with varying polymer concentrations. In general, increasing polymer concentration lengthens the injection time period before the first signs of CGA fluid instability appears.

Table 6-6: Comparison of pressure required for the injection of CGA Fluids with various surfactant and polymer concentrations into a micromodel saturated with water, brine, mineral oil and crude oil

Polymer Concentration (lb/bbl)	Surfactant Concentration (lb/bbl)	Water	Brine	Mineral Oil	Crude Oil
kPa					
0.1	2	4	-	-	-
0.5	2	4	6	63	34
1	2	6	6	76	24
2	2	6	6	134	30
3	2	8	-	-	-
1	0.035	8	-	-	-
2	0.035	8	-	-	-

Table 6-7: Comparison of initial instability for the injection of CGA Fluids with various surfactant and polymer concentrations into a micromodel saturated with water, brine, mineral oil and crude oil

Polymer Concentration (lb/bbl)	Surfactant Concentration (lb/bbl)	Water	Brine	Mineral Oil	Crude Oil
PV					
0.1	2	6	-	-	-
0.5	2	240	106	9	>285
1	2	358	660	7	>440
2	2	>685	>575	155	>417
3	2	>575	-	-	-
1	0.035	>363	-	-	-
2	0.035	363	-	-	-

6.3.3 *Effect of Surfactant Concentration*

Figure 6-28 and Figure 6-29 shows the inlet pressure rise with a water saturated micromodel for 2 and 1 lb/bbl polymer (XG) base fluid respectively. With a base fluid of 2 lb/bbl polymer concentration (Figure 6-28), the pressure drop increases as the surfactant concentration decreases. This also occurs with a base fluid of 1 lb/bbl concentration (Figure 6-29) but to a lesser extent. In Figure 6-28, the 0 lb/bbl surfactant case contains no CGA's and the 0.035 lb/bbl surfactant case contains very little CGA's as this concentration is below the critical micellar concentration.

Figure 6-30 shows images of the CGA injection for different concentrations of surfactant with 2 lb/bbl polymer concentration. It shows that as the surfactant concentration increases there are more microbubbles within the micromodel. This is especially evident when comparing the 0.035 and 2 lb/bbl cases at higher injected pore volumes (200 PV). This would indicate that at a lower concentration of surfactant, there are less microbubbles created and thus we are injecting more polymer base fluid per pore volume than with a higher surfactant concentration. Although a higher pressure drop would indicate better pore blocking ability, the images suggests that contribution of the polymer base fluid to pressure drop is more than that of the CGA microbubbles. At low surfactant concentrations, the injection fluid contains more polymer (and less microbubbles) which is not easily removed from the system. Economically, the use of an air/polymer system reduces the expense of polymer as there is a reduction in the amount of polymer used. Therefore it would not be desirable to use a polymer alone even though the pressure rise is greater.

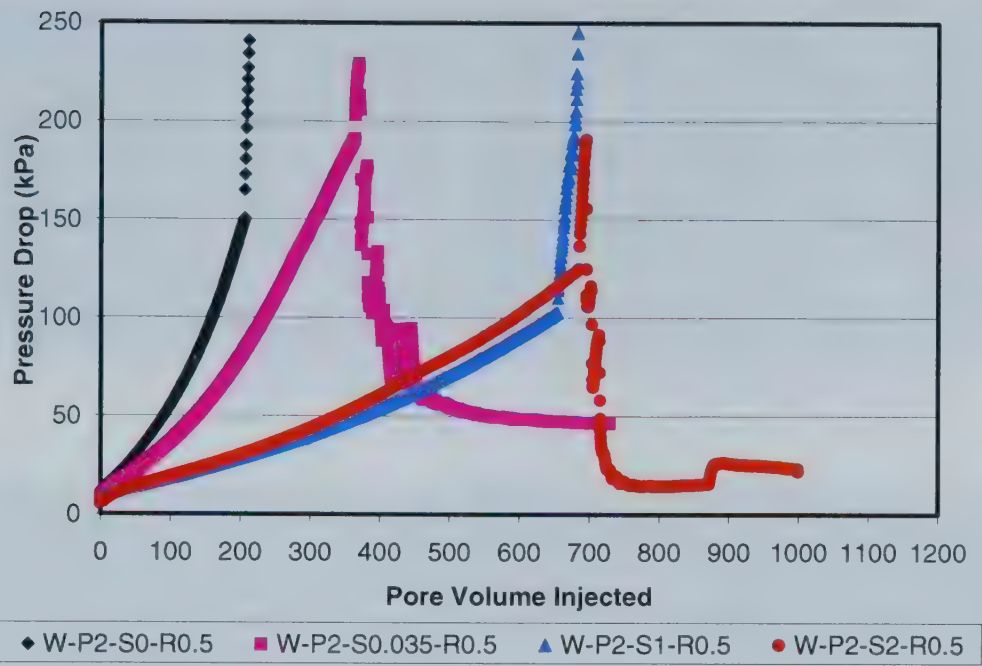


Figure 6-28: Pressure data for aphron injection with a water saturated micromodel for different concentrations of anionic surfactant (DDBS).

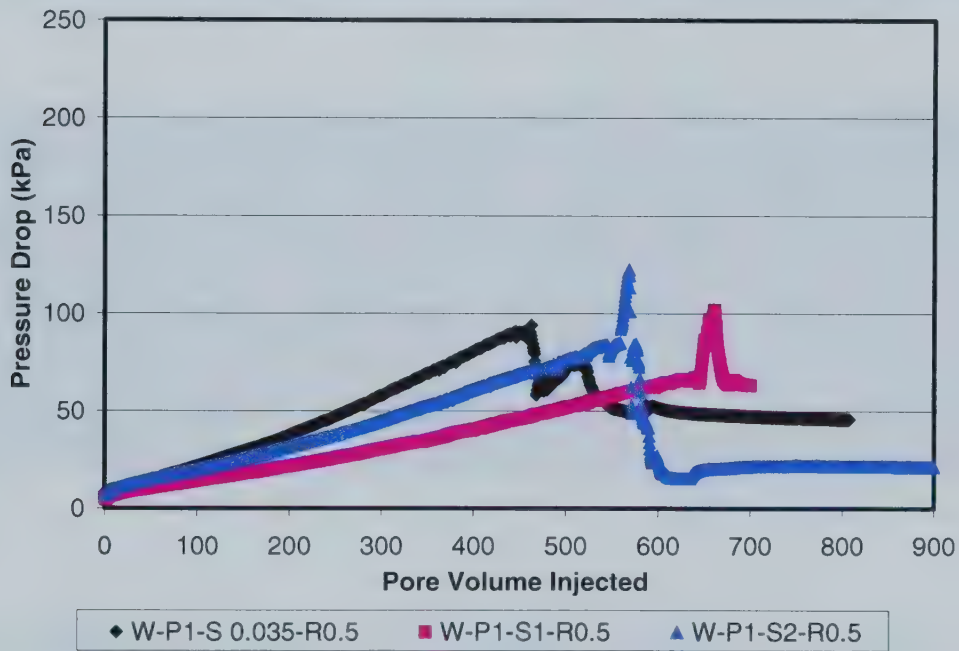


Figure 6-29: Pressure data for aphron injection with a water saturated micromodel for different concentrations of anionic surfactant (DDBS).

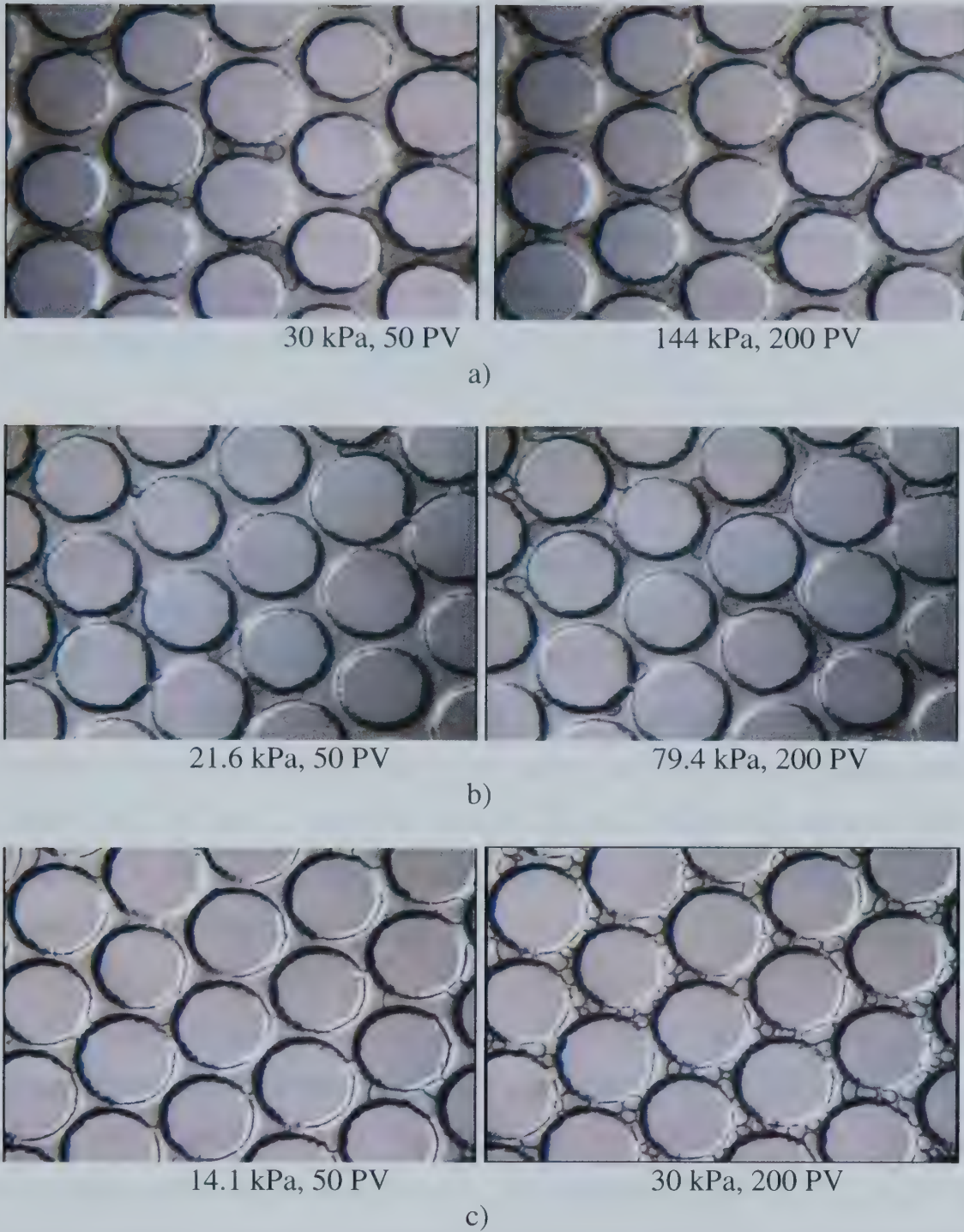


Figure 6-30: Images of CGA flow through the micromodel for a) W-P2-S0-R0.5-M1, b) W-P2-S0.035-R0.5-M1 and c) W-P2-S2-R0.5-M1. Images taken at 1.6 x magnification.

6.3.3.1 Effect of Pore Fluid Type

The change in pressure drop due to flow of CGA fluid through a brine saturated micromodel as a function of CGA fluid's surfactant concentration is given in Figure 6-31. When the results from the water saturated micromodel (Figure 6-28)

are compared to the ones from brine saturated micromodel (Figure 6-31) especially at low surfactant concentrations we can see that there is a difference in pressure drop. Salts alter the critical micellar concentration of surfactants. It is therefore possible that the brine is helping to alter the CGA fluid by changing the micelle concentration within the fluid and thus changing the pressure drop along the micromodel. More research will have to be conducted to better examine the extent of brine on the CGA system.

Figure 6-32 illustrates the pressure drop in the micromodel saturated with mineral oil due to the flow of CGA fluids with different surfactant concentrations. The 0.035 lb/bbl surfactant concentration case is not shown as the pressure needed to inject that fluid was greater than 250 kPa. The figure shows that inlet pressure is greater at lower surfactant concentrations. At lower surfactant concentrations, there are less CGA's in the system and more polymer in the system. Since the mineral oil is more viscous than water and brine, this effect is more evident in Figure 6-32 as well. Once the mineral oil was re-injected, the pressure drop increased to a value that exceeded the limitations of the micromodel and thus the experiments were terminated.

The pressure drop due to the flow of CGA fluids with different surfactant concentrations through the micromodel saturated with crude oil is given in Figure 6-33. Unlike the mineral oil case, the change in surfactant concentration did not have much effect on the inlet pressure. This is because the viscosity of the crude oil is much less than that of the mineral oil and therefore the injection pressure is less than with the mineral oil. However, the viscosity of the crude oil is high enough to affect the pressure drop once CGA injection was terminated and the crude oil was re-injected back into the micromodel.

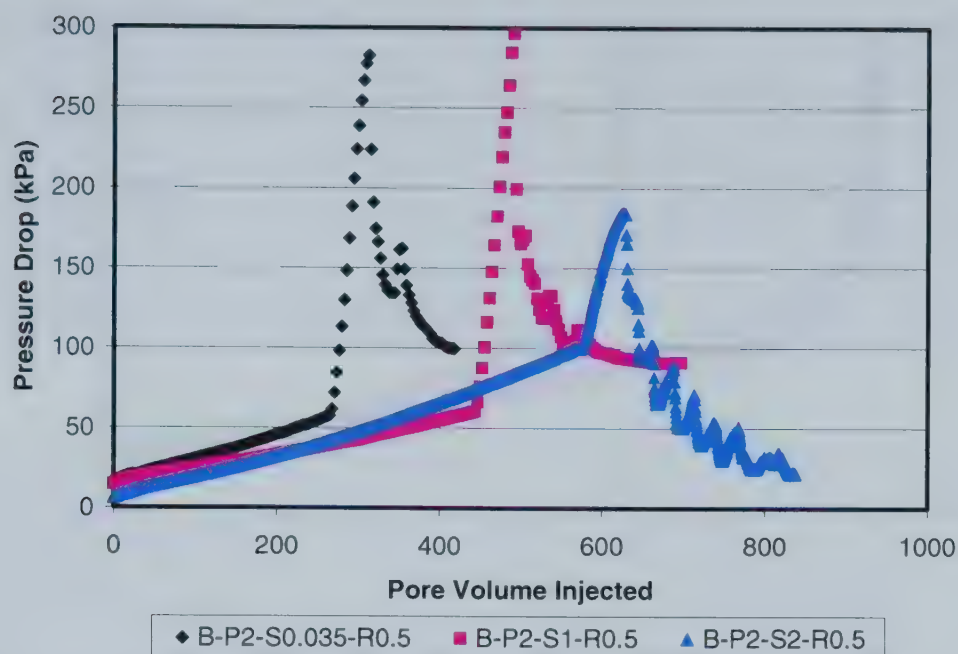


Figure 6-31: Pressure data for CGA fluid injection with a brine saturated micromodel for different concentrations of anionic surfactant (DDBS).

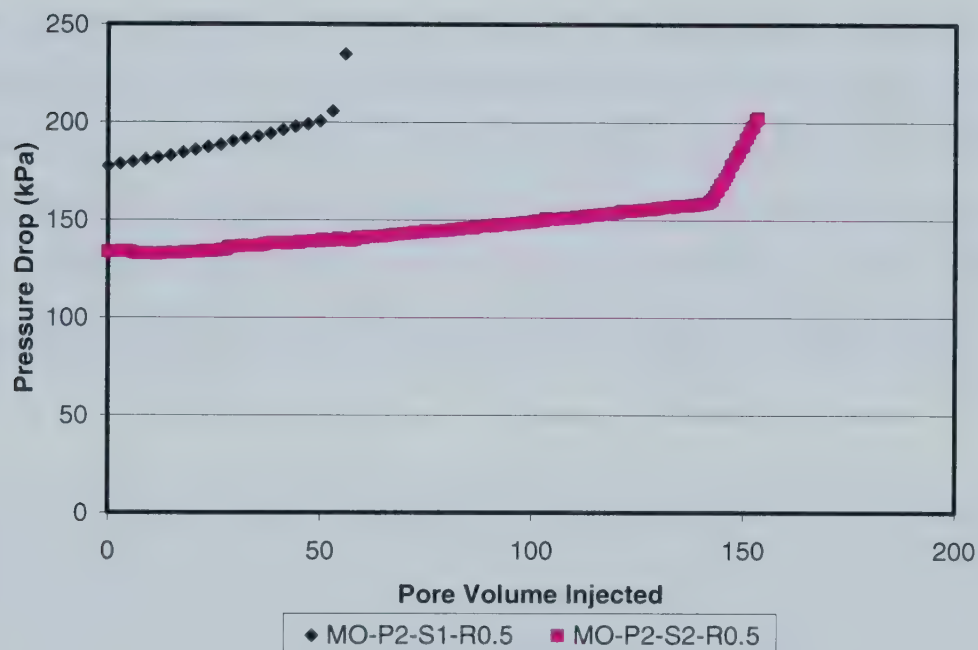


Figure 6-32: Pressure data for aphron injection with a mineral oil saturated micromodel for different concentrations of anionic surfactant (DDBS) **note Injection pressure is too high for the 0.035 lb/bbl surfactant concentration case.

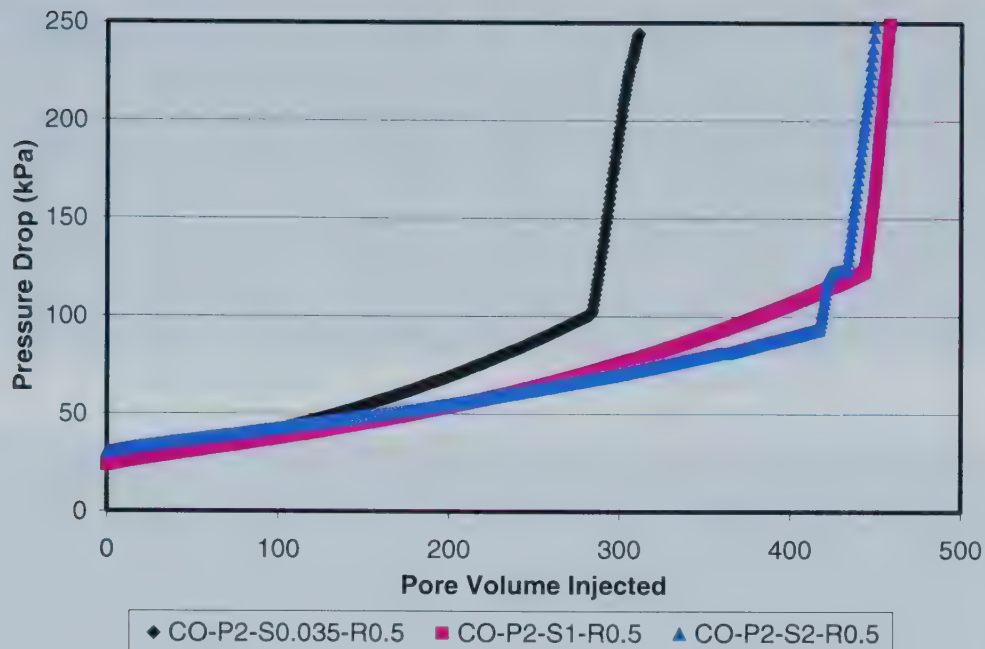


Figure 6-33: Pressure data for CGA injection with a crude oil saturated micromodel for different concentrations of anionic surfactant (DDBS).

Figure 6-34 to Figure 6-36 shows images of the CGA fluid with 0.035 lb/bbl surfactant and 2 lb/bbl polymer concentration being injected into micromodel saturated with various fluids. For all experiments conducted using CGA fluid with 0.035 lb/bbl of surfactant, the amount of CGA's flowing into the micromodel is not significant. Therefore, it is important to formulate a CGA fluid with surfactant concentrations greater than the critical micellar concentration.

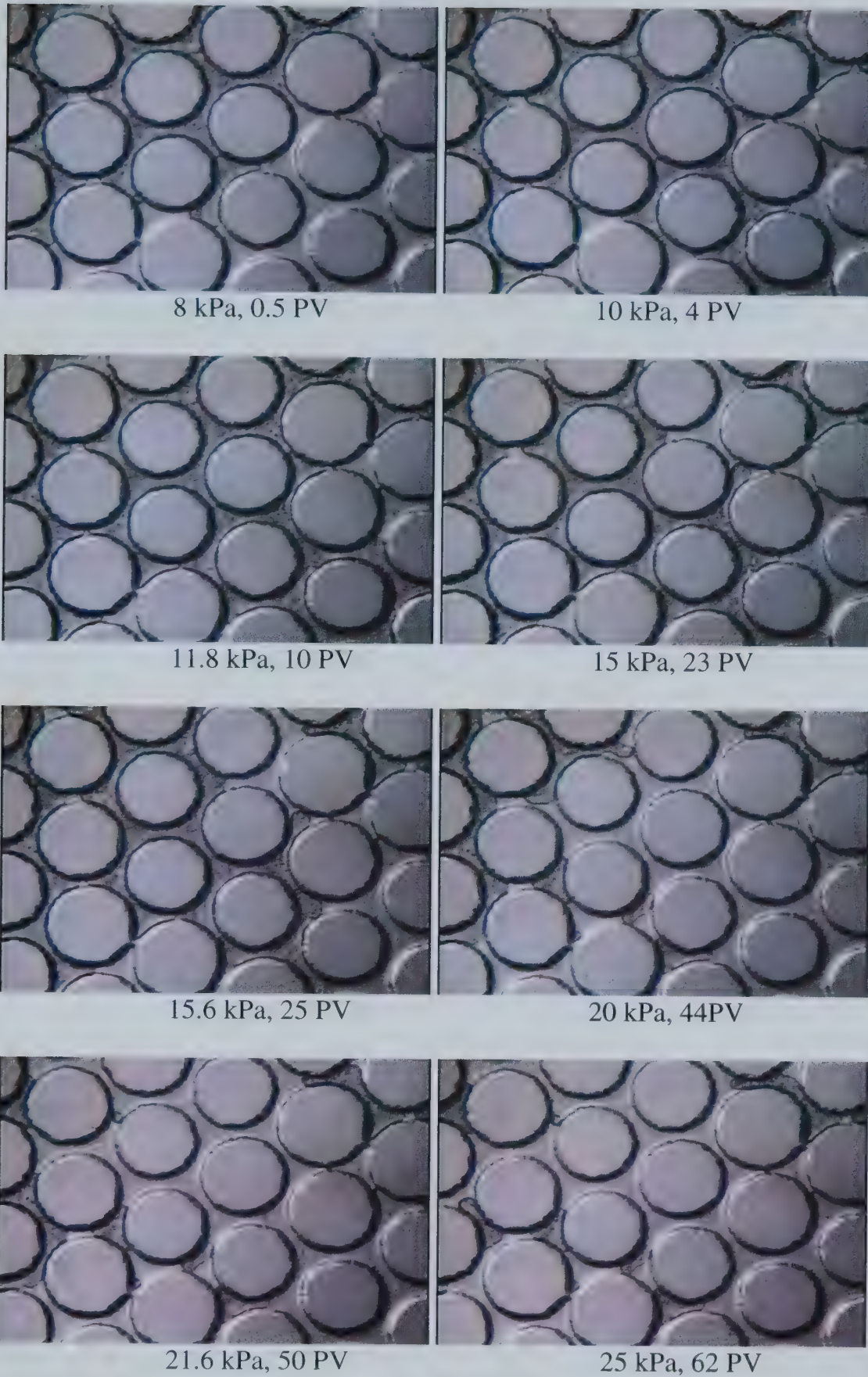
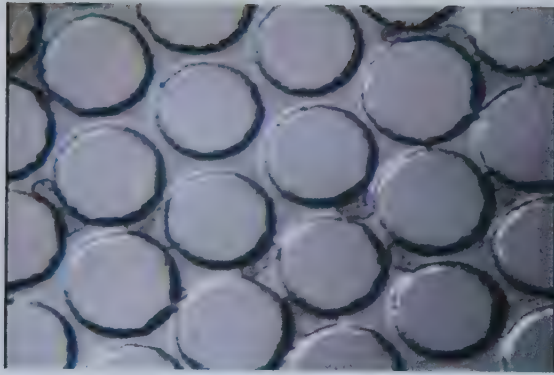
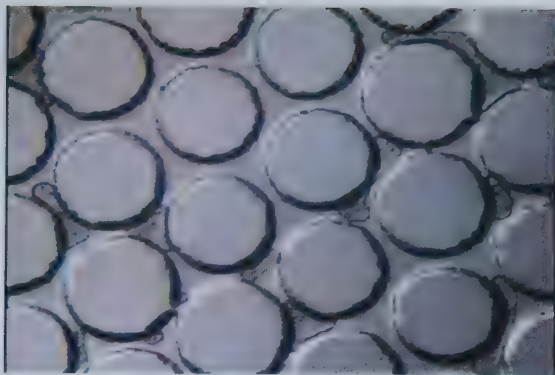


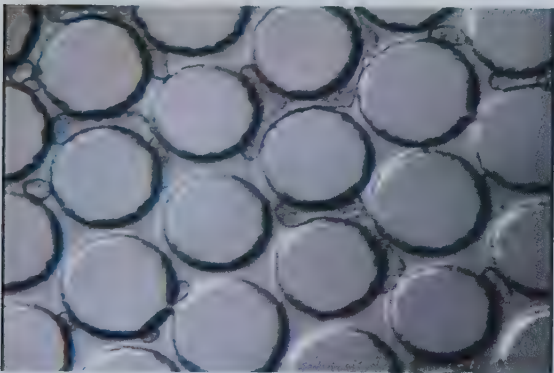
Figure 6-34: Images of afoam flow through the micromodel for W-P2-S0.035-R0.5-M1. Images taken at 1.6 x magnification.



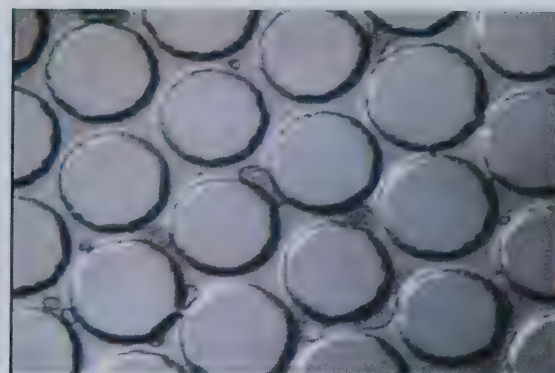
30 kPa, 79 PV



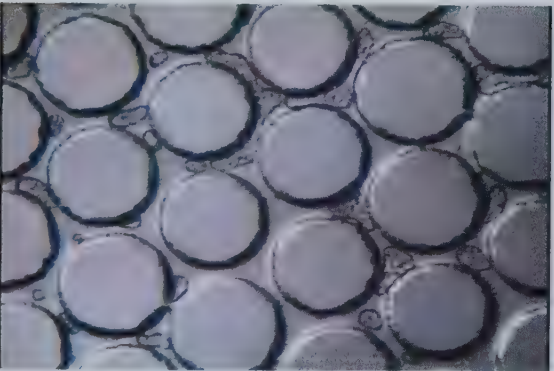
36.6 kPa, 100 PV



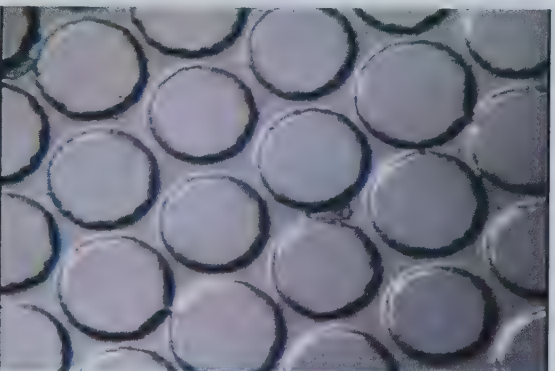
79.4 kPa, 200 PV



191 kPa, 364 PV



112.5 kPa, 400 PV



52 kPa, 520PV

Figure 6-34: Continued

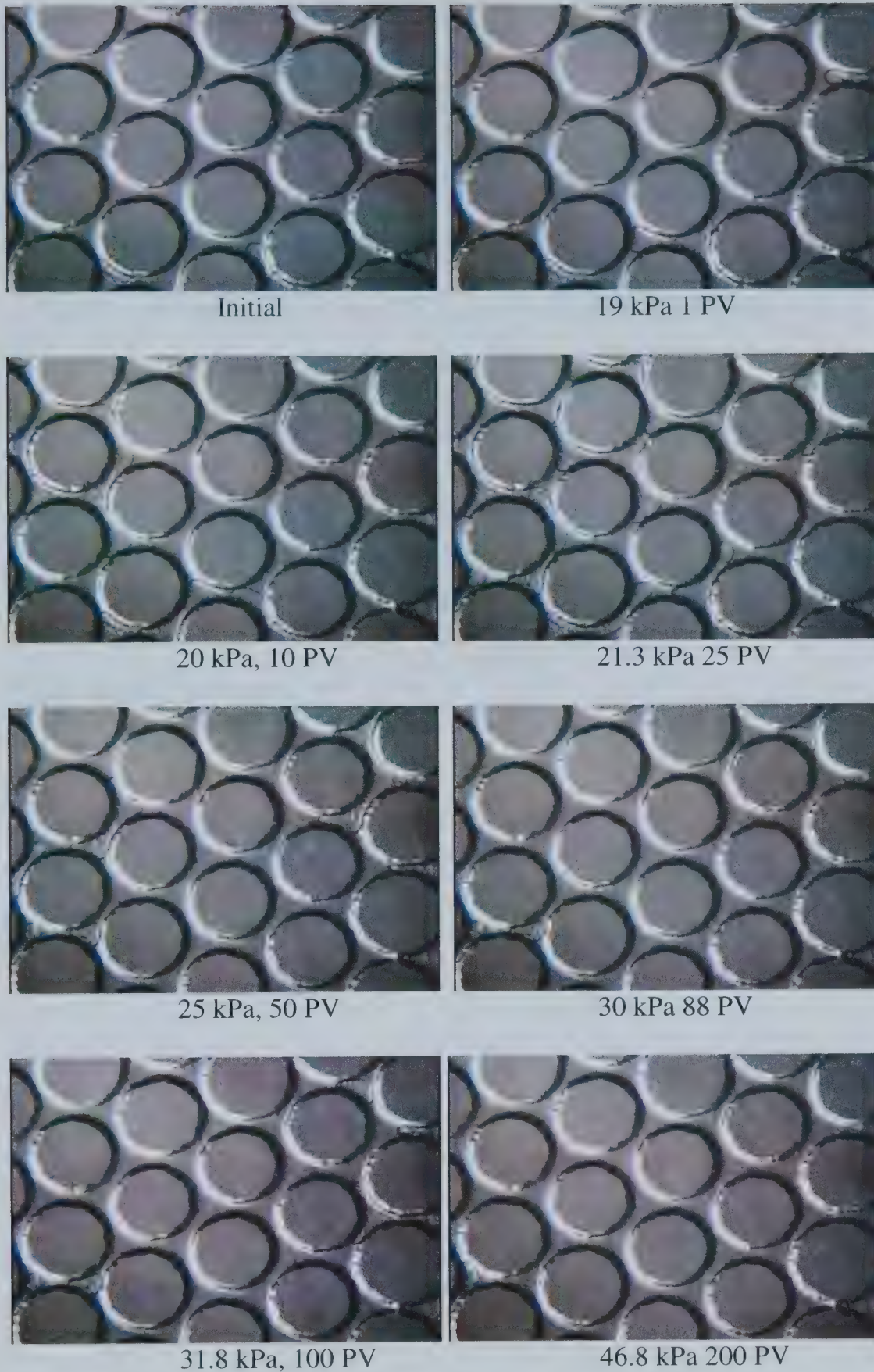
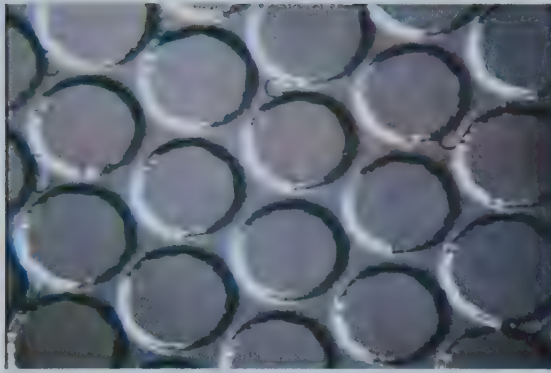
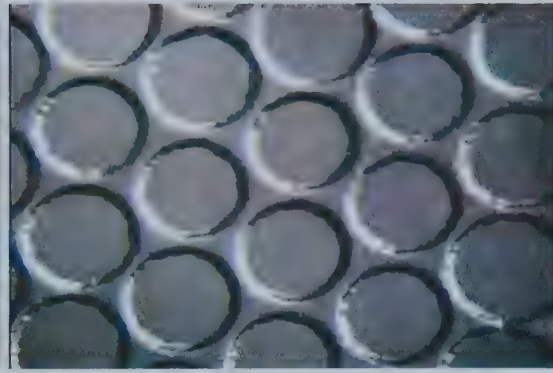


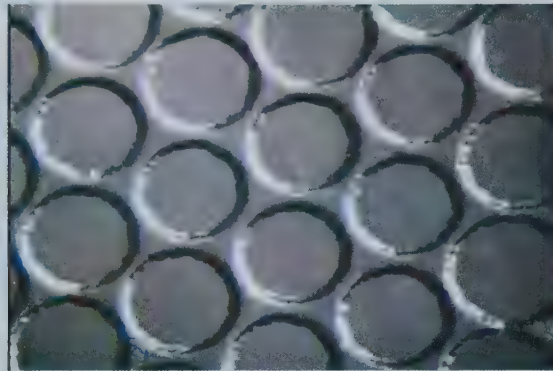
Figure 6-35: Images of CGA fluid flow through the micromodel for B-P2-S0.035-R0.5-M1. Images taken at 1.6 x magnification.



57 kPa, 253 PV



100 kPa 400 PV



100 kPa 409 PV

Figure 6-35: Continued



Initial



24 kPa, 1 PV



25.6 kPa, 10 PV



28.4 kPa, 25 PV



30 kPa, 34 PV

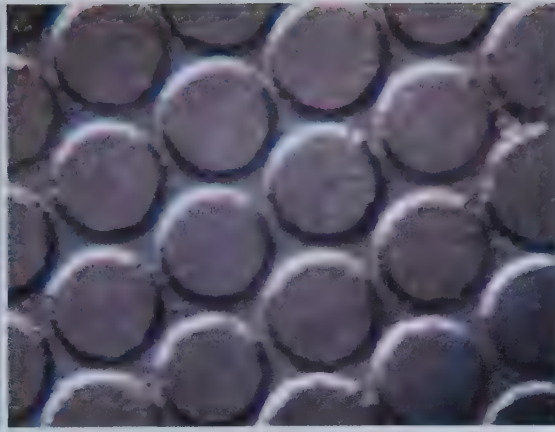


32.7 kPa, 50 PV

Figure 6-36: Images of CGA fluid flow through the micromodel for CO-P2-S0.035-R0.5-M1. Images taken at 1.6 x magnification.



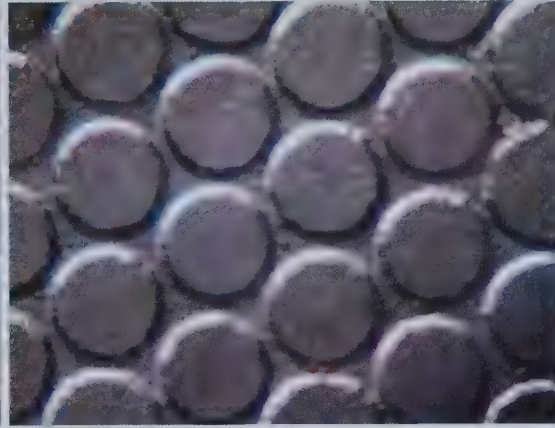
35 kPa, 63 PV



40 kPa, 90 PV



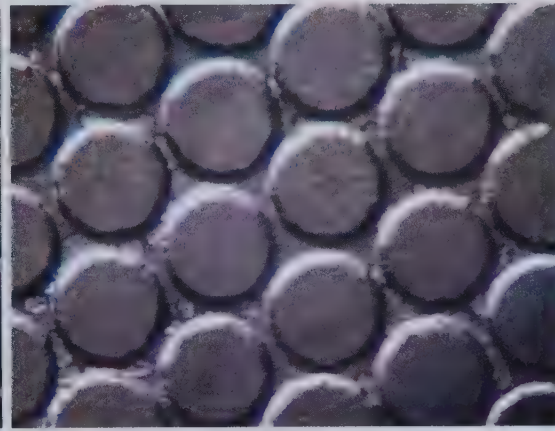
42.1 kPa, 100 PV



45 kPa, 114 PV



50 kPa, 135 PV



69 kPa, 200 PV

Figure 6-36: Continued



99 kPa, 279 PV

Figure 6-36: Continued

Figure 6-37 and Figure 6-38 compare the pressure drops due to the flow of CGA fluids with 0.035 lb/bbl and 2 lb/bbl surfactant concentrations through the micromodel saturated with water, brine, mineral oil and crude oil. The mineral oil data is absent from Figure 6-37 as the injection pressure exceeded the micromodel limitations. Figure 6-37 shows that the micromodel saturated with water had the greatest pressure drop. This was most likely due to the change in the experimental set-up between the water and brine saturation experiments as discussed previously. Figure 6-38 illustrates that the magnitude of the pressure drop is related to the viscosity of the fluid.

Table 6-8 summarizes the injection pressures for all experiments comparing the effect of surfactant concentration. It shows that the higher the surfactant concentration, the lower the pressure needed to inject the CGA fluid. This is once again due to the compressibility of the system.

Table 6-9 shows the pore volume injected until an initial instability occurred for all CGA fluids with varying surfactant concentrations. It shows that as the surfactant concentration increases for the water saturated micromodel, the stability of the fluid increases. This conclusion cannot be drawn for the experiments saturated with other fluids as the CGA fluid was stable for the entire length of injection for those experiments.

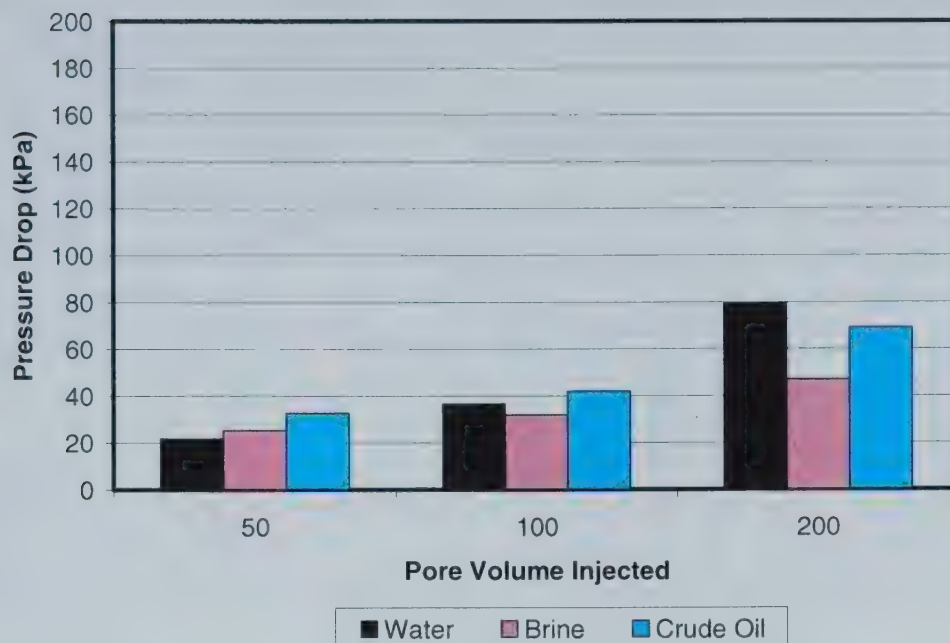


Figure 6-37: Comparison of pressure data for CGA injection with different fluid types with 2 lb/bbl polymer (XG), 0.035 lb/bbl surfactant (DDBS) and a flow rate of 0.5 cc/min.

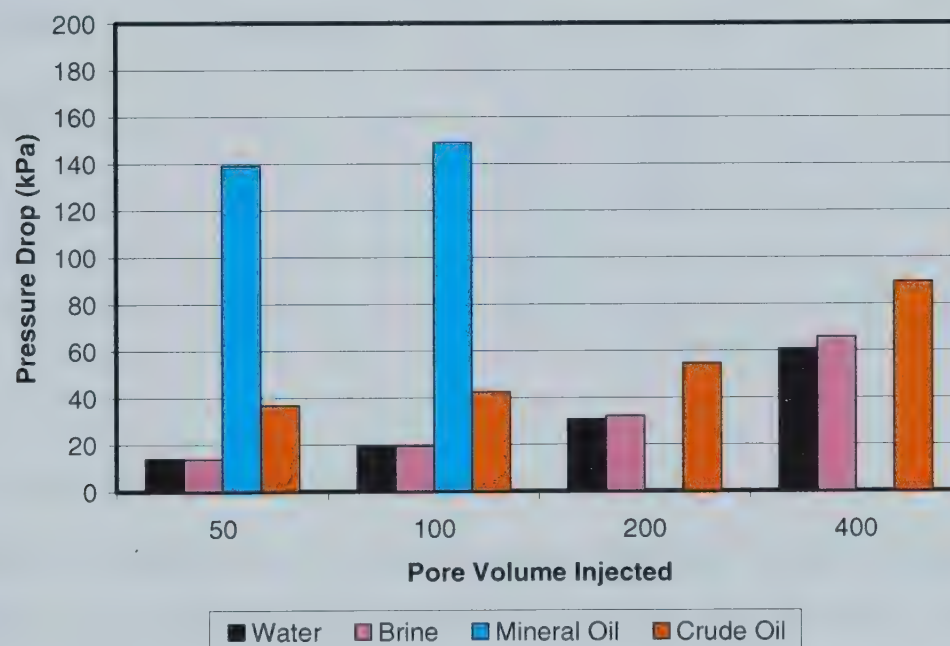


Figure 6-38: Comparison of pressure data for CGA injection with different fluid types with 2 lb/bbl polymer (XG), 2 lb/bbl surfactant (DDBS) and a flow rate of 0.5 cc/min.

Table 6-8: Comparison of pressure required for the injection of CGA Fluids with various surfactant and polymer concentrations into a micromodel saturated with water, brine, mineral oil and crude oil

Surfactant Concentration (lb/bbl)	Polymer Concentration (lb/bbl)	Water	Brine	Mineral Oil	Crude Oil
kPa					
0	2	11	-	-	-
0.035	2	8	17	-	24
1	2	8	15	177	24
2	2	6	6	134	30
0.035	1	8	-	-	-
1	1	6	-	-	-
2	1	6	6	76	24

Table 6-9: Comparison of initial instability for the injection of CGA Fluids with various surfactant and polymer concentrations into a micromodel saturated with water, brine, mineral oil and crude oil

Surfactant Concentration (lb/bbl)	Polymer Concentration (lb/bbl)	Water	Brine	Mineral Oil	Crude Oil
PV					
0.035	2	363	>265	-	>283
1	2	>650	>445	>50	>444
2	2	>685	>575	155	>417
0.035	1	>363	-	-	-
1	1	342	-	-	-
2	1	358	660	7	>440

6.3.4 Effect of Permeability

The effect of permeability on CGA injection and flow in porous media was examined. The difference in pressure at the inlet with Matrix 1 (200 mD permeability) and Matrix 2 (50 mD permeability) is illustrated in Figure 6-39. It shows that the pressure increase with Matrix 2 is much slower than that for Matrix 1 and does not increase at a fast rate until water is injected at approximately 430 PV. Matrix 2 has a much smaller permeability than Matrix 1 and a pore radius that is less than half of that of Matrix 1. Therefore, the pressure needed to inject the CGAs into the micromodel with Matrix 2 should be much greater and the

capillary pressure is much higher. An increasing capillary pressure will cause a collapse of the foam lamella (Morrow, 1991) and the foams become less stable. With a less stable CGA fluid, there would be a slower pressure rise because of coalescence of the CGA fluid.

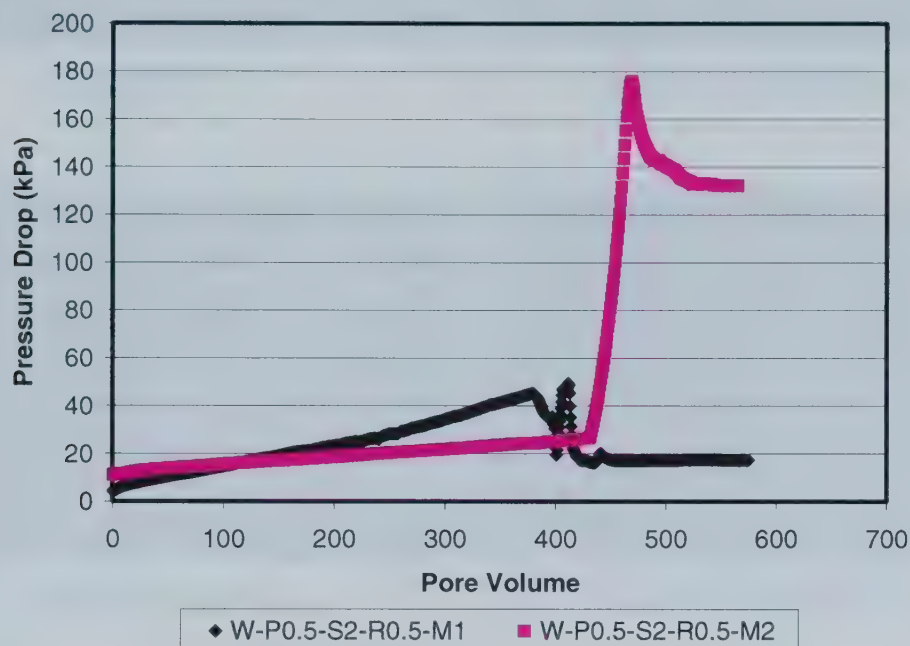
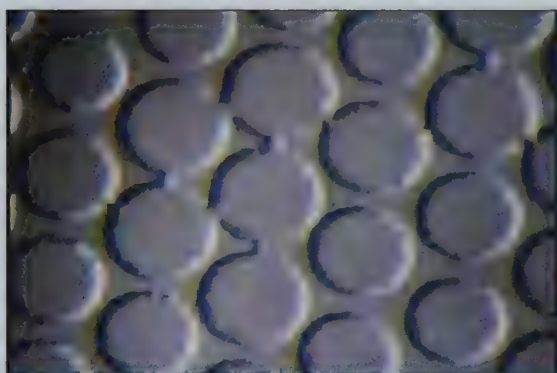
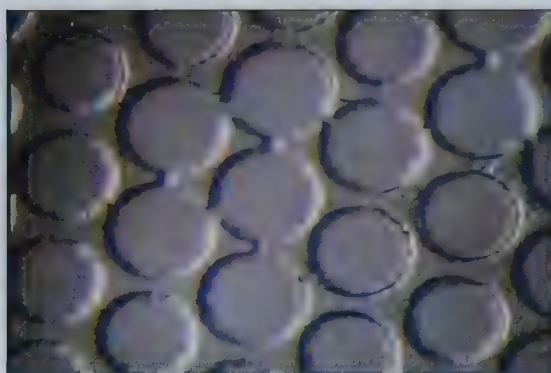


Figure 6-39: Pressure data for CGA injection of 0.5 lb/bbl polymer (XG) base fluid at a rate of 0.5 cc/min for Matrix 1 and Matrix 2.

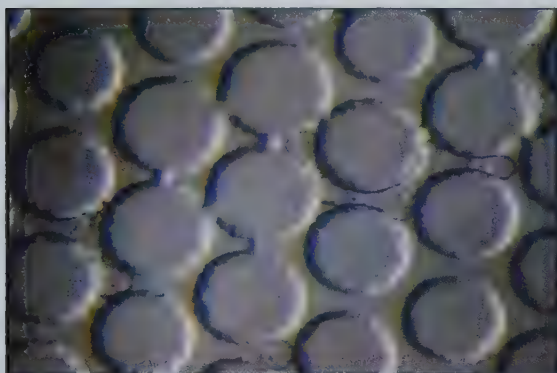
Figure 6-40 illustrates the images of the 0.5 lb/bbl polymer (XG) fluid with Matrix 2. It shows that although some air entered the cell at 11.6 kPa, there was little change in the flow up to 30 kPa. At 51.6 kPa, some air movement is observed in the cell but foam flow was not very evident. This supports the theory that due to high capillary pressure, the CGA fluid is unstable. When comparing the images obtained for Matrix 2 with what was obtained from Matrix 1 (Figure 6-41), it is evident that there is much less or no CGAs in Matrix 2 while the image of Matrix 1 shows the micromodel is filled with CGA fluid.



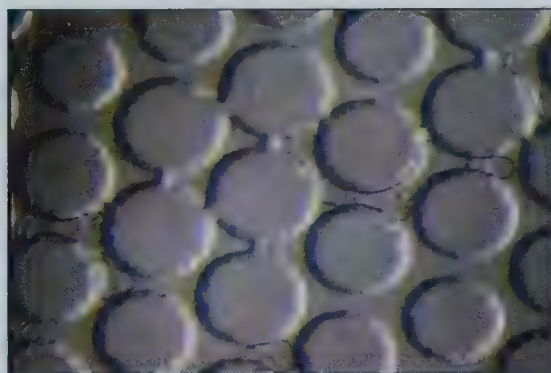
0kPa, 0PV



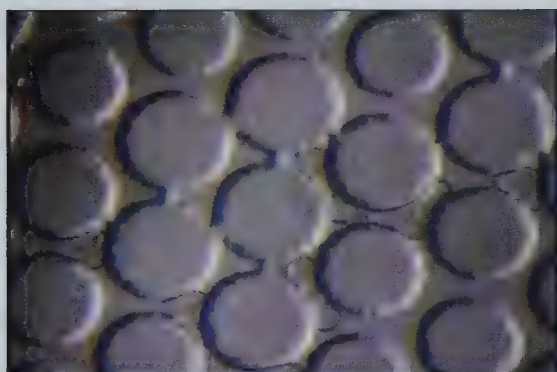
Before foam injection, 11.6 kPa



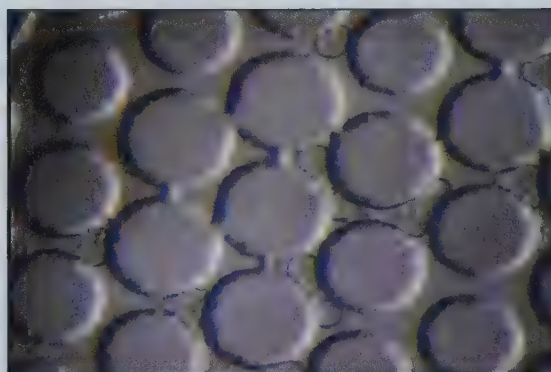
15 kPa, 84.3 PV



20 kPa, 241.7 PV

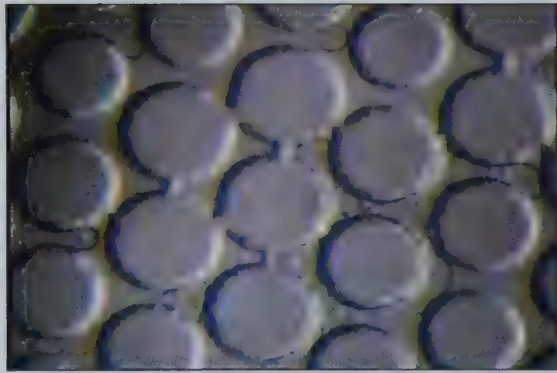


25 kPa, 397.2 kPa

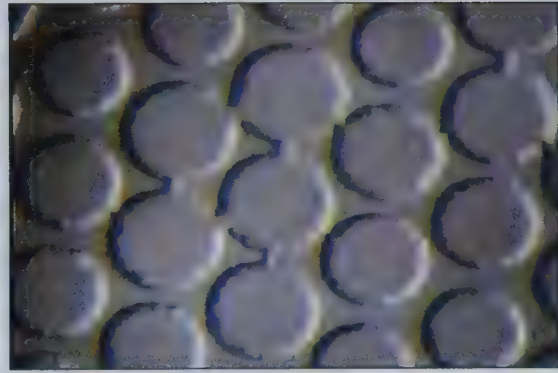


30 kPa, 434.3 PV

Figure 6-40: Images of CGA flow through the microcell with matrix 2 for 0.5 lb/bbl polymer (XG) at a flow rate of 0.5 cc/min. Images taken at 4.0 x magnification.

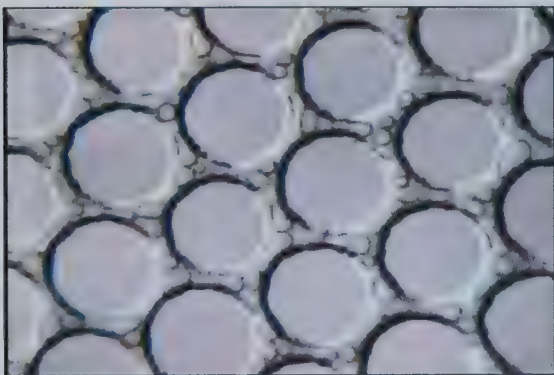


51.6 kPa, 441.7 PV

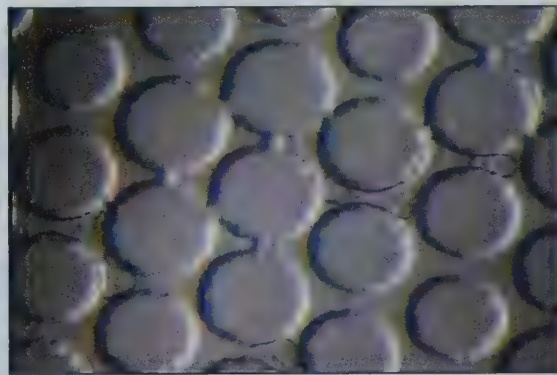


132.2 kPa, 555.6 PV

Figure 6-40: Continued



30 kPa, 267.15 PV, Matrix 1



20 kPa, 241.7 PV, Matrix 2

Figure 6-41: Comparison of the CGA fluid flow through the two matrixes used in this study for similar CGA fluid compositions

Since CGA fluid was not detected in the micromodel with Matrix 2 using the experimental procedure that was successful for all experiments previously reported with Matrix 1, a different experimental procedure was developed to understand the magnitude of pressure needed to inject the CGA fluid into the micromodel. The injection line was saturated with a CGA fluid slug followed by a slug of water. The slug of water was used because it is an incompressible fluid and therefore higher pressures can be achieved at a faster rate. A faster rate was needed because in the previously discussed experiment with Matrix 2, coalescences and instabilities of the fluid occurred. A faster rate will reduce coalescences and instabilities by decreasing the time needed to inject the fluid. The water was injected at a rate of 0.1 cc/min in order to slow the pressure rise enough so that the initial CGA injection point can be detected. The results of this

test are shown in Figure 6-42. It shows that there is initial movement in the cell between 30 and 40 kPa and the slow movement continues up to 120 kPa. Although there was air movement inside the cell, the flow of the CGAs that was evident in all cases previously discussed for Matrix 1 is not evident in Matrix 2 (see Figure 6-41). It must be noted though that the depth of Matrix 2 is more than half the depth of Matrix 1. This will elongate the CGAs inside the cell. Therefore, the air that is evident may be CGAs bubbles but the quantity of the bubbles was not great indicating the sufficient pressures were not reached for adequately CGA flow through the micromodel.

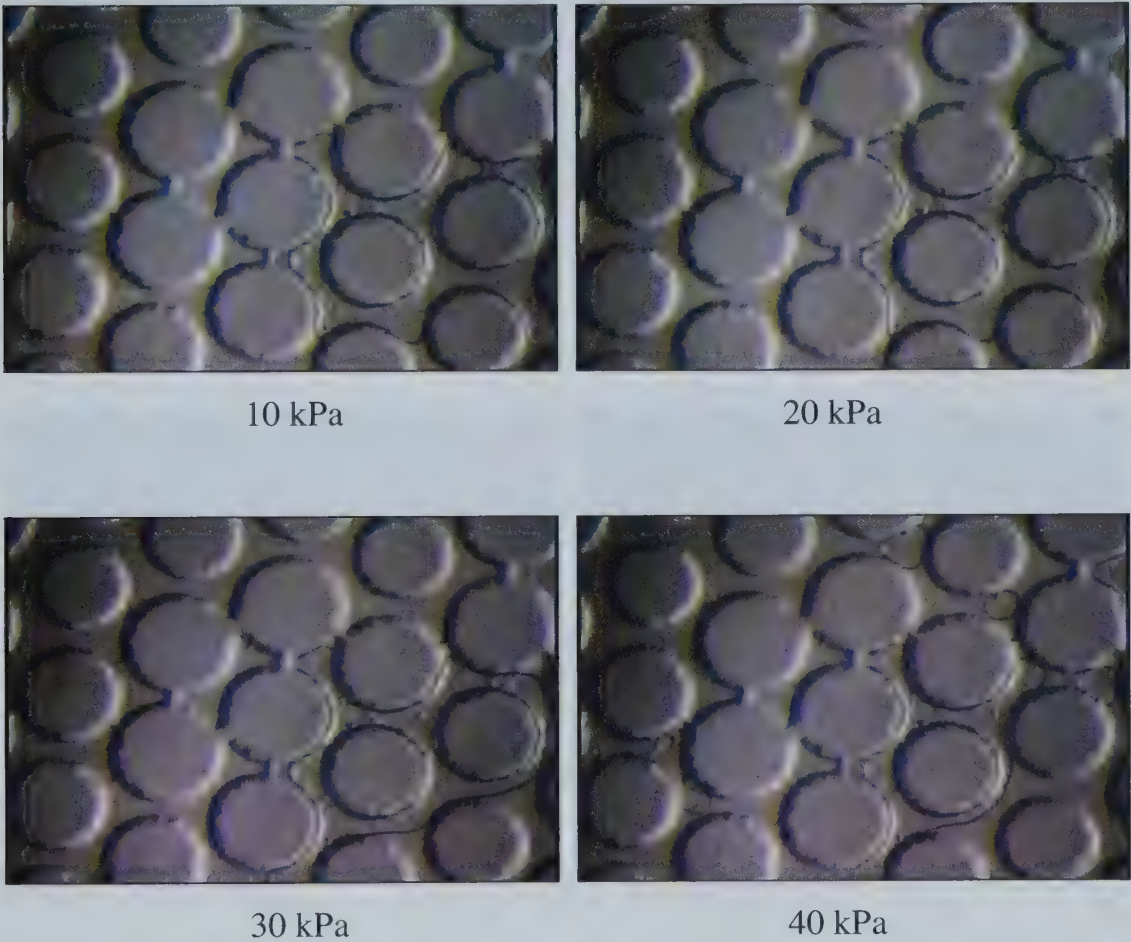
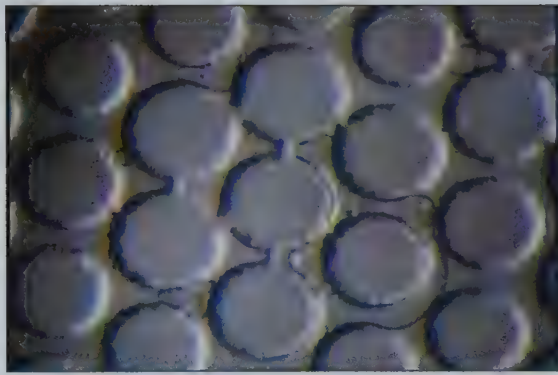
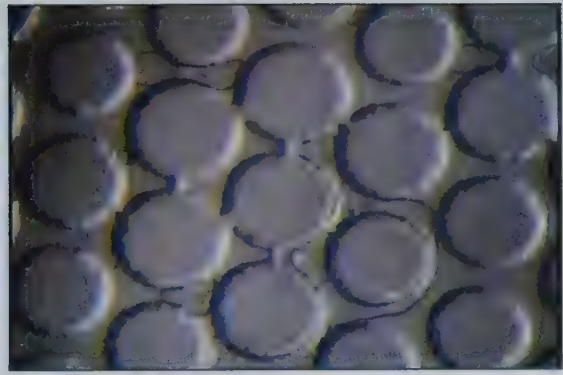


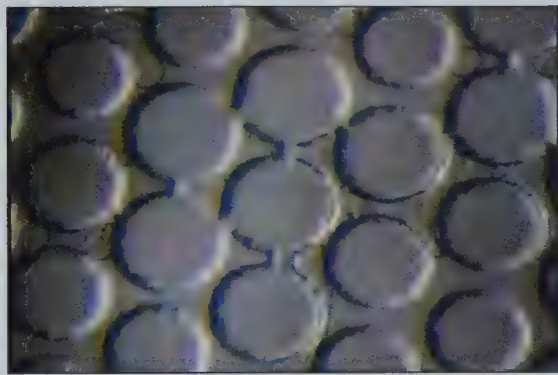
Figure 6-42: Images of CGA flow through the micromodel with matrix 2 for 0.5 lb/bbl polymer (XG). Images taken at 4.0 x magnification.



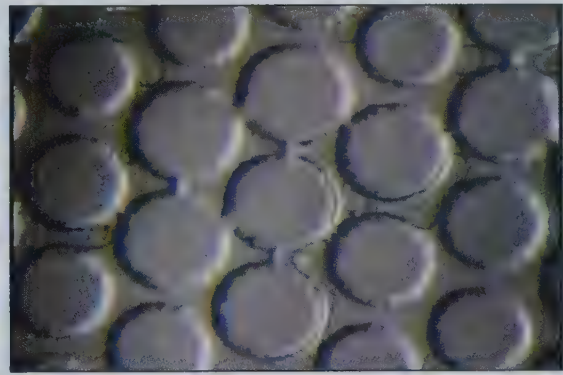
50 kPa



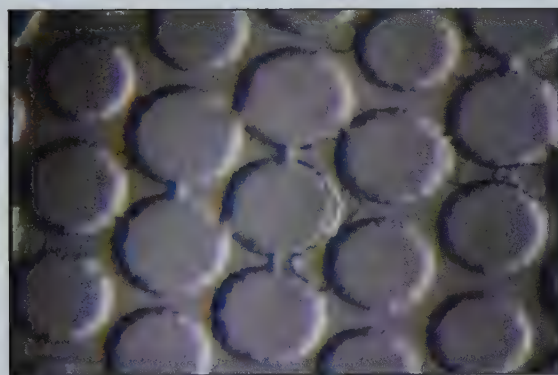
60 kPa



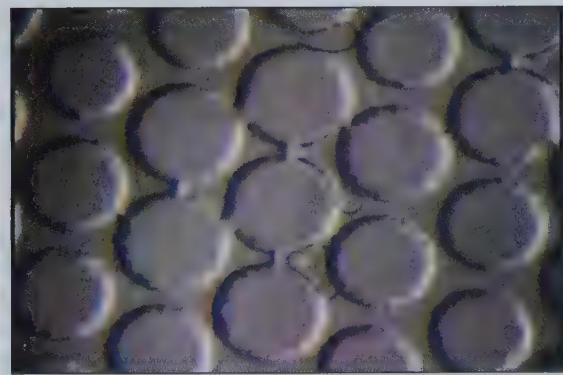
70 kPa



80 kPa



90 kPa



100 kPa

Figure 6-42: Continued

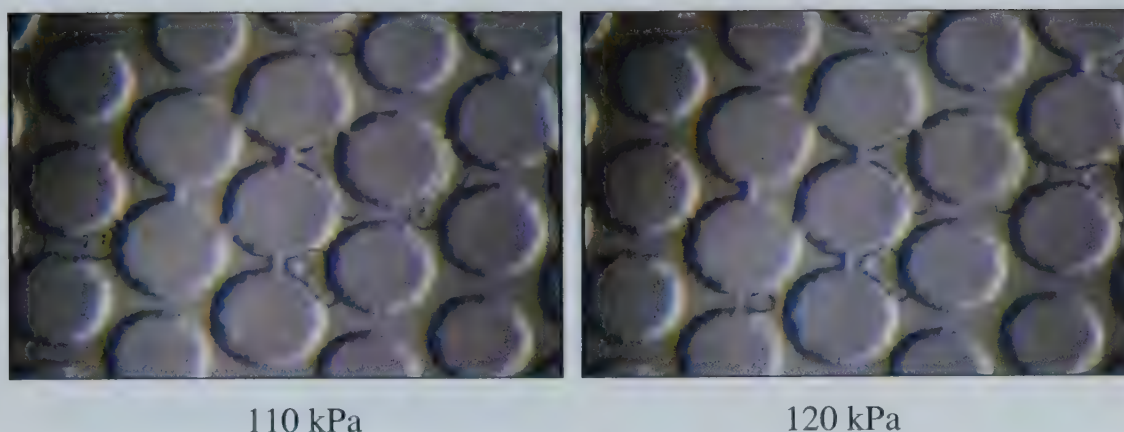


Figure 6-42: Continued

6.4 SUMMARY

The following conclusions can be drawn from the visualization experiments:

- A stable foam was created and injected into the micromodel.
- The porous media was blocked by the stable foam as indicated by the continuous pressure rise. Therefore, drilling with aphronized fluid will reduce filtration (fluid) loss into the formation.
- A CGA of 60 μm bubble will invade a porous medium saturated with water with pore diameter of 50 μm at around 10 kPa.
- Pore diameter of 20 μm and less reduced the stability of the CGA fluid.
- The CGA fluid was successfully removed by water after injection for the micromodel tests indicating that the effect of the CGA is reversible.
- The pressure increase in a low permeability micromodel (50 mD) was much slower than that for higher permeability (200 mD) micromodel for a fixed flow, indicating less stable foam in lower permeable situations.
- The pressure drop across the micromodel increased as the viscosity of the saturating fluid increased.
- Pressure drop increased at a faster rate as the base fluid viscosity increased indicating that a more viscous base fluid increased the stability of the CGA fluid.
- A polymer concentration of 3 lb/bbl or greater impedes the generation of CGAs.

- Long term stability of the CGA fluid was not achieved with a polymer concentration of less than 0.1 lb/bbl.
- Pressure drop increased at a faster rate at lower surfactant concentrations. As surfactant concentration decreased, the amount of CGA's in the system decreased and viscous polymer injection increased.
- With the exception of one case, the CGA fluid effectively displaced the crude oil from the water wet micromodel.
- For the conditions in these experiments, the optimum concentrations for the most effective CGA blocking is a polymer concentration greater than 0.1 lb/bbl and less than 3 lb/bbl and a surfactant concentration of 1 lb/bbl or greater.

7 COREFLOW INVESTIGATION OF THE CGA BRIDGING ABILITY

CGAs in a drilling fluid are expected to form a bridge-like structure across rock surface. Sandpack tests were conducted with radial and linear apparatuses to determine the maximum pressure drop across a porous medium with CGA fluid. The maximum pressure drop per unit distance (pressure gradient) has a direct relation to the bridging and blocking of pores. Permeability, CGA composition and wettability was varied in order to understand the dominating factors for CGA blocking.

7.1 APPARATUSES AND MATERIALS USED FOR THE COREFLOW STUDY OF THE CGA BRIDGING MECHANISM

7.1.1 Equipment Used for the Sandpack Study

7.1.1.1 Radial Sandpack Study

A diagram of the radial sandpack pressure vessel utilized in this study is given in Figure 7-1 and Figure 7-2. The aluminum pressure vessel is equipped with two production wells at the wall of the cell and one injection well at the center of the cell. The injection tube sits inside a larger tube which can be utilized either for injection or as a fluid bypass. The two production tubes and the larger injection tube are partially slotted and screened. The cell was designed to roughly simulate radial flow by equipping the inner diameter of the aluminum pressure vessel with a screen. This screen was utilized to encourage flow around the outer edge of the pressure vessel to the producer tubes.

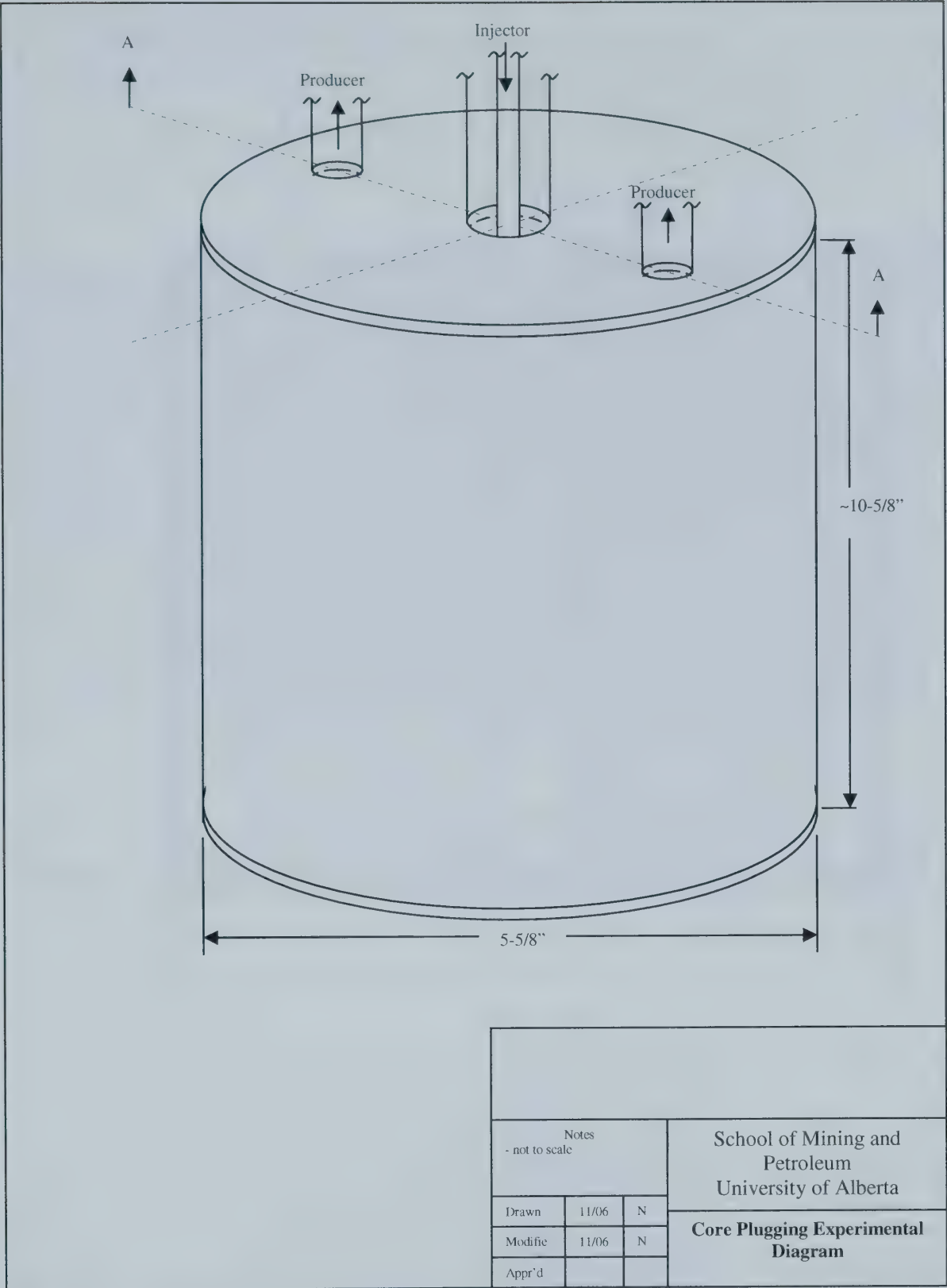


Figure 7-1: Schematic of the sandpack pressure vessel

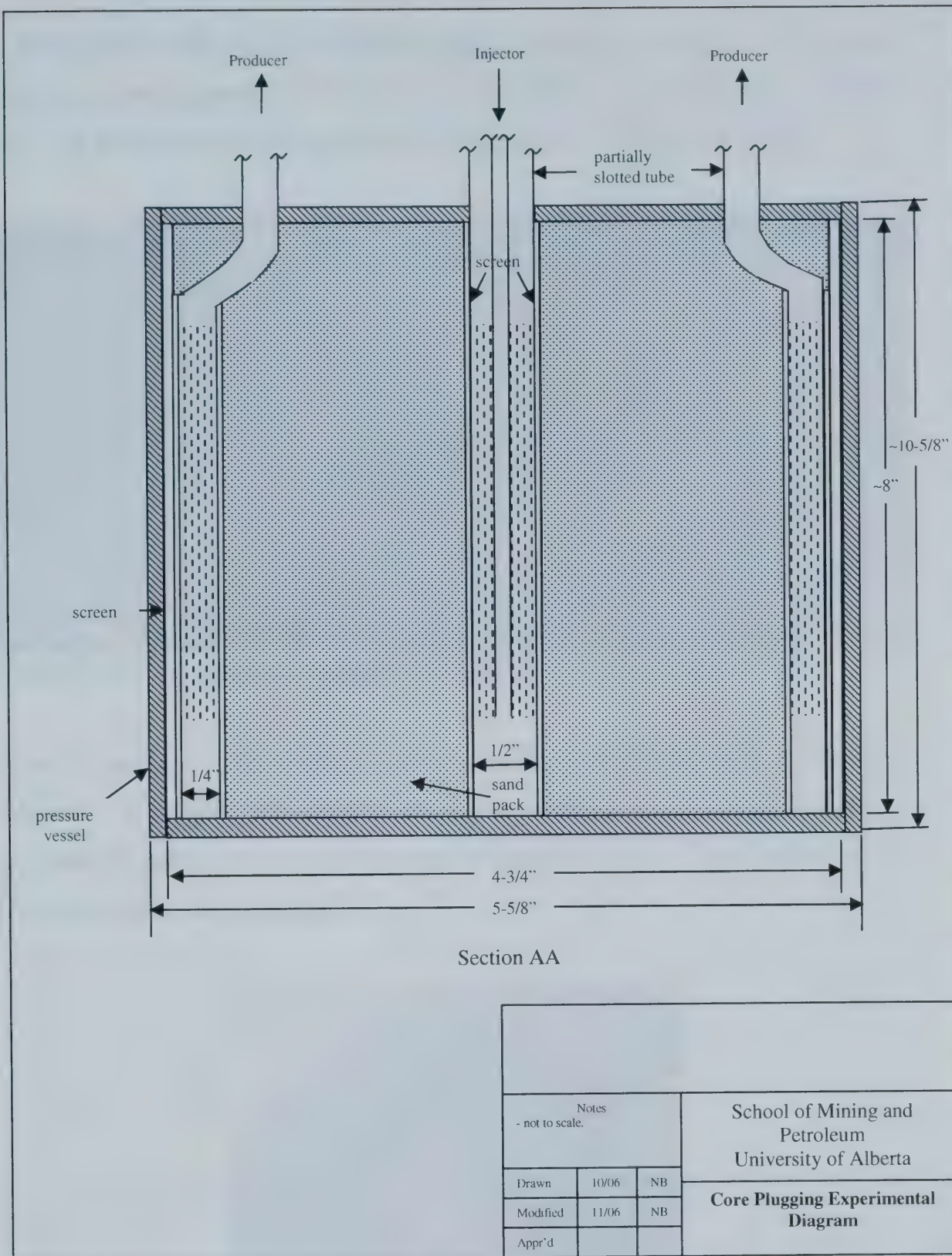


Figure 7-2: Cross sectional schematic of the sandpack pressure vessel

7.1.1.2 Linear Sandpack Study

A photograph of the linear coreflood apparatus is given in Figure 7-3. The inside diameter of the apparatus is 4.064 cm and the length of the apparatus is 32.385 cm. The maximum working pressure of the apparatus is 3200 psig at 58°C.



Figure 7-3: Photograph of the linear sandpack pressure vessel

Alberta Innovates – Technology Future’s (ATIF, formally the Alberta Research Council) CT Scanner was used in the linear sandpack test to examine what is happening inside of the sandpack at intervals during the test. A photograph of the CT Scanner is given in Figure 7-4.



Figure 7-4: Photograph of AITF's CT Scanner

7.1.2 *Materials Used for the Coreflow Study*

7.1.2.1 Radial Sandpack Study

A polymer (XG) – water mixture was used as the base drilling fluid. The base fluid was prepared using a method similar to the one described in Chapter 3. A Waring commercial blender was used to mix the fluid. Aphron fluid was generated by adding sodium dodecyl benzene sulfonate (DDBS), an anionic surfactant, to the base fluid and high speed mixing with a Polytron Generator for a 30 second duration. Concentrations of 0 and 2 lb/bbl were used for the polymer (XG) base fluid and 0 and 2 lb/bbl for the anionic (DDBS) surfactant.

F110 (0.210 to 0.053 mm dia.) sand or 40 to 70 (0.47 to 0.262 mm dia.) mesh sand was used for the radial sandpack study.

The reservoir fluids used in this study are described in Section 6.1.4. 5 vol% trimethylchlorosilane and 95% toluene mixture was used to alter the wettability of the sand for the wettability study.

7.1.2.2 Linear Sandpack Study

A polymer (XG) – water mixture was used as the base drilling fluid. A Waring commercial blender was used to mix the fluid. Aphron fluid was generated by adding sodium dodecyl benzene sulfonate (DDBS), an anionic surfactant, to the base fluid and mixing at high speed with a Polytron Generator for a 30 second duration. A concentration of 2 lb/bbl was used for the polymer (XG) base fluid and anionic (DDBS) surfactant mixture.

F110 (0.210 to 0.053 mm dia.) sand was used for this study.

7.2 EXPERIMENTAL PROCEDURE USED FOR THE COREFLOW STUDY
OF THE CGA BRIDGING MECHANISM

7.2.1 Experimental Set-Up

7.2.1.1 Radial Sandpack Study

A schematic of the experimental set-up used for the radial sandpack test is given in Figure 7-5. The experimental set-up consists of a pump, two accumulators used to inject the CGA fluid and the reservoir fluid, the sandpack pressure vessel, a differential pressure transducer and a data acquisition system which recorded at intervals of 1 minute. Pressure was measured at the inlet and outlet of the sandpack vessel using a Rosemount[®] differential pressure transmitter. Pressure values were recorded using an Agilent[®] Data Acquisition. A Quizix (QX-1500) pump was used to inject the fluid.

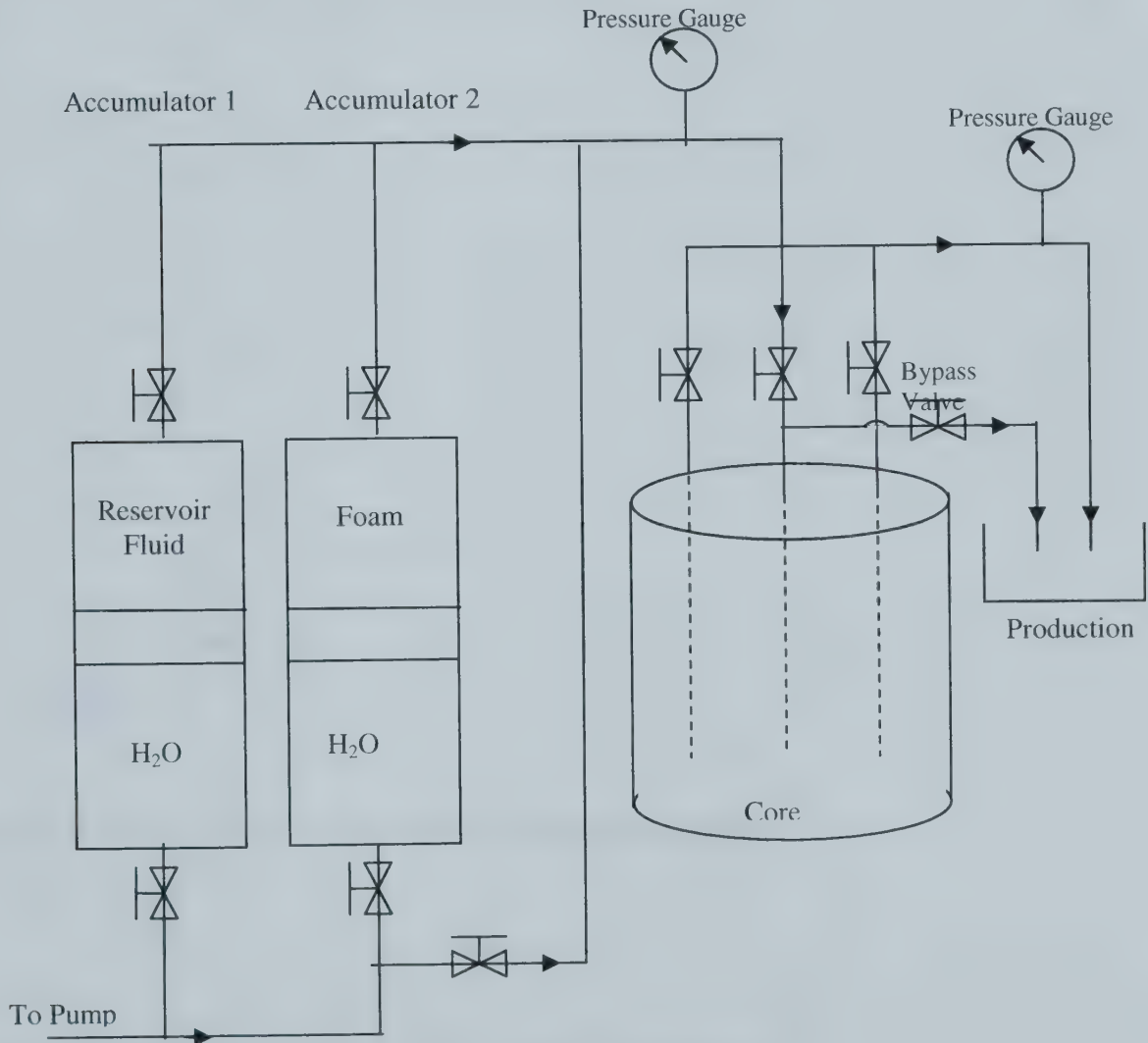


Figure 7-5: Schematic of the radial experimental set-up

7.2.1.2 Linear Sandpack Study

A schematic of the experimental set-up used for the linear sandpack test is given in Figure 7-6. The experimental set-up consists of a pump, an accumulator used to inject the CGA fluid, the linear sandpack pressure vessel, a pressure transducer and a data acquisition system which recorded at intervals of 1 and 15 minutes. Pressure was measured at the inlet of the sandpack vessel. A Quizix (QX-1500) pump was used to inject the fluid.

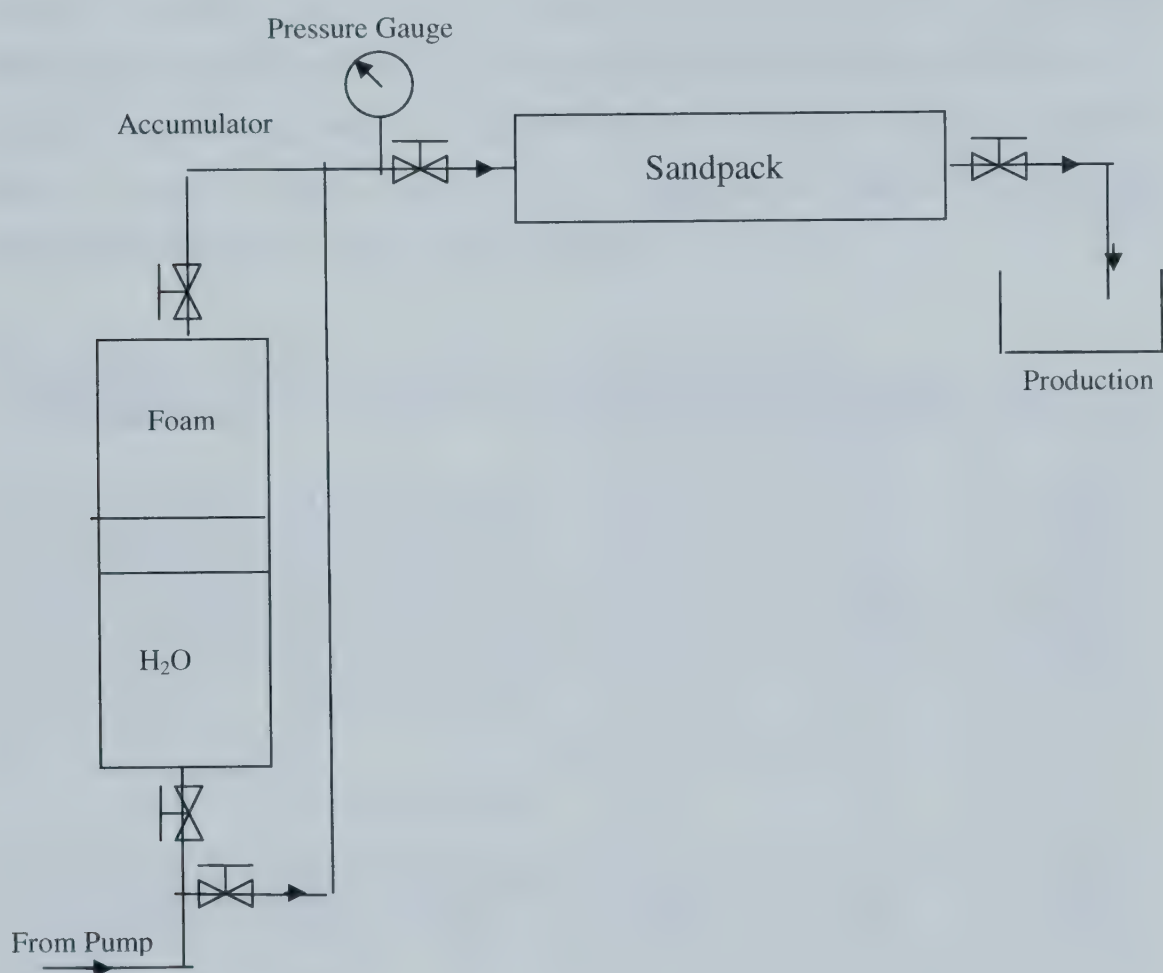


Figure 7-6: Schematic of the linear experimental set-up

7.2.2 Experimental Procedure

7.2.2.1 Radial Sandpack Study

The experimental procedure can be subdivided into five categories: sand packing procedure, wettability alteration procedure (if necessary), saturation fluid injection, CGA fluid injection and reinjection of the saturation fluid.

7.2.2.1.1 Sandpacking Procedure

Each pressure vessel was packed with sand via a sandpacking injection port at the bottom of the pressure vessel. Either F110 (0.210 to 0.053 mm dia.) sand or 40 to 70 (0.47 to 0.262 mm dia.) mesh sand was used. The pressure vessel was mechanically agitated while the sand was poured into the vessel at intervals. In between the pouring intervals the pressure vessel was also manually agitated. Table 7-1 lists the sand used for each experiment as well as the porosity, permeability and pore volume of the sandpack.

Table 7-1: Properties of the sandpack for each experiment

Experiment #	Sand	Porosity (%)	Permeability (D)	PV (cm ³)
B-P2-S2-R3-k3	F110 (water wet)	33.4	3.0	584.6
B-P2-S2-R4-k3	F110 (water wet)	33.4	3.0	584.6
W-P2-S2-R3-k3	F110 (water wet)	33.7	3.0	591.0
W-P2-S0-R3-k3	F110 (water wet)	33.6	3.0	589.1
W-P0-S2-R3-k3	F110 (water wet)	33.7	3.0	589.5
MO-P2-S2-R3-k3	F110 (water wet)	33.5	3.0	587.0
CO-P2-S2-R3-k3	F110 (water wet)	33.6	3.0	588.1
B-P2-S2-R3-k42	40/70 (water wet)	32.6	42.0	571.6
MO-P2-S2-R3-k3-OW	F110 (oil wet)	33.8	3.0	592.8

- B – Brine

CO – Crude Oil

k - Permeability

MO – Mineral Oil

OW – Oil Wet
- P – Polymer

R – Rate

S – Surfactant

W – Water

7.2.2.1.2 Wettability Alteration Procedure

To investigate the effect of wettability, the normally water-wet sand was chemically altered to become oil-wet. The alteration of the sand from hydrophilic to hydrophobic is achieved through methylation (Blake and Ralston, 1985). Methylation of the F110 sand was conducted by submersing the sand in 5 vol% trimethylchloronsilane and 95% toluene. The sand was placed in a fumehood and the toluene was evaporated leaving behind the altered sand.

7.2.2.1.3 Saturation Fluid Injection

Table 7-2 summarizes the saturation fluids used for each experiment. The saturation fluid is pumped into the sandpack vessel from the saturation fluid accumulator (Figure 7-5). In the water-wet case, the sandpack was initially saturated with brine or water. Saturation was achieved by injecting more than 1.5 PV (pore volumes) into the sandpack and by cycles of pressure build-up and release. After water or brine injection, the pack was then injected with oil where applicable. Pressure cycles were also used to for the oil saturation. In the oil-wet sandpack case, the pack was saturated with mineral oil alone using pressure cycles.

Table 7-2: Summary of the saturation fluids for each experiment.

Experiment #	Primary Saturation Fluid	Secondary Saturation Fluid
B-P2-S2-R3-k3	Brine	-
B-P2-S2-R4-k3	Brine	-
W-P2-S2-R3-k3	Water	-
W-P2-S0-R3-k3	Water	-
W-P0-S2-R3-k3	Water	-
MO-P2-S2-R3-k3	Brine	Mineral Oil
CO-P2-S2-R3-k3	Brine	Crude Oil
B-P2-S2-R3-k42	Brine	-
MO-P2-S2-R3-k3-OW	Mineral Oil	-

B – Brine
CO – Crude Oil
k - Permeability
MO – Mineral Oil
OW – Oil Wet

P – Polymer
R – Rate
S – Surfactant
W – Water

7.2.2.1.4 CGA Fluid Injection

Once the sandpack is saturated with the saturation fluid, the CGA fluid is pumped into the sandpack vessel from the accumulator (Figure 7-5). Initially, the valves at the producer tubes are closed and the bypass valve is opened. This was continued until CGA fluid was present at the outlet of the bypass valve. This was done to remove the saturation fluid from the injection lines and to replace it with CGA fluid. The bypass valve was then closed and the production valves were opened initiating the test. Pressure was measured at the inlet and outlet of the sandpack and the outlet pressure was maintained at atmospheric for all runs. The CGA fluid was injected at a fixed flow rate into the sandpack until an approximate maximum pressure was obtained. A close to maximum pressure is defined as the point where there is an insignificant pressure increase for an extended period of time during CGA injection. Once this point was reached, the foam injection was stopped and reservoir fluid was injected back into the pressure vessel. After approximately every two pore volumes of injection, the injection fluid accumulator needed to be replenished. The injection of fluid was then stopped by shutting off the pump and closing all the valves and more fluid was placed in the injection accumulator. Once the fluid was in the accumulator, the accumulator was repressurized back to the pressure of the sandpack using the pump. The valves were re-opened and the test was continued. Care was taken during this process to ensure that no extra air was added to the system.

Figure 7-7 gives an example of a typical experimental result. All results are reported in pressure drop per meter of distance traveled through the porous medium. The graph is separated into two sections: CGA Injection and Saturation Fluid Re-Injection.

During the CGA injection, CGA fluid was directly injected into the sandpack at a given fixed flow rate. The pressure rose in the sandpack as the CGA fluid invaded and blocked the pores of the pack. From the graph, at approximately the

2 and 4 PV intervals, there were decreases in pressure. At these intervals, the sandpack was shut-in and the fluid in the CGA accumulator was replenished. The drops in pressure occurred because the accumulator pressure was dropped to atmospheric pressure in order to replenish it. Once replenished, the accumulator pressure was increased to the approximate pressure of the sandpack using the pump. This caused a ‘pressure bump’ during the experiment. As the experiment progressed, the amount of fluid that could be injected at each accumulator interval decreased. This was due to the fact that as the pressure of the system increased (ie sandpack, accumulators, injection lines and pump), the fluid became more compressed. Since the CGA fluid is composed of gas and liquid, pressure will cause the fluid to compress and this will reduce the total volume of the fluid. With a smaller fluid volume available to inject, the amount of time needed to return the pressure rise after each shut-in becomes more critical. This is because the fluid is being injected at a fixed flow rate (ie volume/time). As the total volume decreases, the time to inject the total volume also decreases.

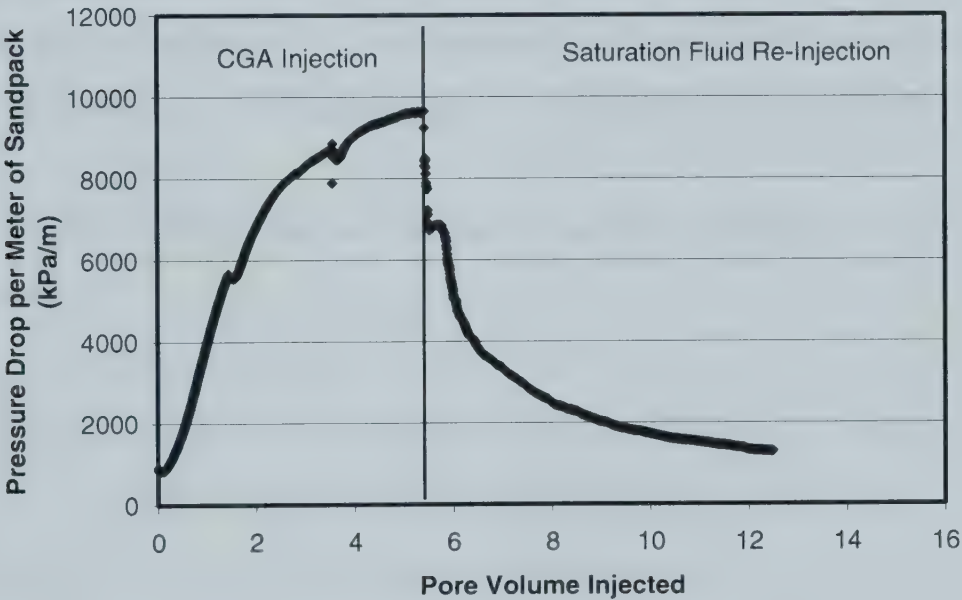


Figure 7-7: Typical experimental run in the radial sandpack

Eventually, the pressure came to an approximate maximum pressure (around 5 pore volumes (PV) (Figure 7-7), where more injection of CGA fluid did not

increase the pressure in the pack appreciably. The approximate maximum pressure provides a good estimate of the maximum pressure drop per unit length (ie., pressure gradient) that can be achieved due to the flow of CGA fluid through the porous medium. A higher pressure drop indicates that there is more resistance to flow through the porous medium. The section of the graph labeled as saturation fluid re-injection indicates the section where the injection fluid was switched from CGA fluid to the original saturation fluid.

7.2.2.1.5 Re-injection of Saturation Fluid

Reservoir fluid was re-injected into the sandpack after the maximum pressure with the CGA fluid was reached. This was done to determine how easily the CGA fluid could be removed from the system and to also get an indication of the residual permeability. The fluid was injected at the same rate as the foam until an approximate minimum pressure was reached. An approximate minimum pressure is defined as the point where there is an insignificant pressure decrease for an extended period of time during the fluid injection. In Figure 7-7, the section of the graph labeled as saturation fluid re-injection indicates the section after the injection fluid was switched from CGA fluid to the original saturation fluid. As the CGA fluid is removed from the sandpack, the pressure decreases back to the original pressure that was recorded during the saturation of the sandpack.

Table 7-3 lists the experiments conducted and the parameters used for those experiments.

Table 7-3: Experiments conducted in this study

Experiment #	Perm . (D)	Saturation Fluid	% Saturation	Polymer Conc. (lb/bbl)	Surfactant Conc. (lb/bbl)	Flow Rate (cc/min)
B-P2-S2-R3-k3	3.0	Brine	100	2	2	3
B-P2-S2-R4-k3	3.0	Brine	100	2	2	4
W-P2-S2-R3-k3	3.0	Water	100	2	2	3
W-P2-S0-R3-k3	3.0	Water	100	2	0	3
W-P0-S2-R3-k3	3.0	Water	100	0	2	3
MO-P2-S2-R3-k3	3.0	Mineral Oil	87	2	2	3
CO-P2-S2-R3-k3	3.0	Crude Oil	85	2	2	3
B-P2-S2-R3-k42	42.0	Brine	100	2	2	3
MO-P2-S2-R3-k3-OW	3.0	Mineral Oil	100	2	2	3

B – Brine

CO – Crude Oil

k - Permeability

MO – Mineral Oil

OW – Oil Wet

P – Polymer

R – Rate

S – Surfactant

W – Water

7.2.2.2 Linear Sandpack Study

The experimental procedure can be subdivided into five categories: sandpacking procedure, saturation fluid injection, CGA fluid injection, reinjection of the saturation fluid and CT scanning.

7.2.2.2.1 Sandpacking Procedure

The pressure vessel was packed with sand through the injection end. The pressure vessel was agitated manually while the sand was poured into the vessel at intervals. The porosity of the sandpack was 34.4%, with a permeability of 3D and a pore volume of 147 cm³.

7.2.2.2.2 Saturation Fluid Injection

The saturation fluid (water) was pumped into the sandpack vessel via the pump. Saturation was achieved after injecting more than 1.5 PV (pore volumes) of water into the sandpack and by cycles of pressure build-up and release.

7.2.2.2.3 CGA Fluid Injection

Once the sandpack was saturated with water, the CGA fluid was pumped into the sandpack vessel from the accumulator (Figure 7-6). Pressure was measured at the inlet of the sandpack and the outlet pressure was maintained at atmospheric. The CGA fluid was injected at a constant flow rate into the sandpack until an

approximate maximum pressure was obtained. Approximate maximum pressure is defined as the point where there was an insignificant pressure increase for an extended period of time during CGA injection. Once this point was reached, the foam injection was stopped and reservoir fluid (water) was injected back into the pressure vessel.

In order to compare the linear experiment with the radial experiments, it was important to maintain as many of the operating parameters as possible (ie porosity, permeability, velocity of the fluid) between the sets of experiments. The porosity and permeability can be maintained by using the same type of sand. The fluid velocity should also be maintained for comparison purposes. During CGA injection in the radial apparatus, the injection rate was fixed of 3 cc/min. The corresponding fluid velocity in the radial sandpack decreased with distance from the injection well. The velocity as a function of radius in the radial sandpack is given in Figure 7-8.

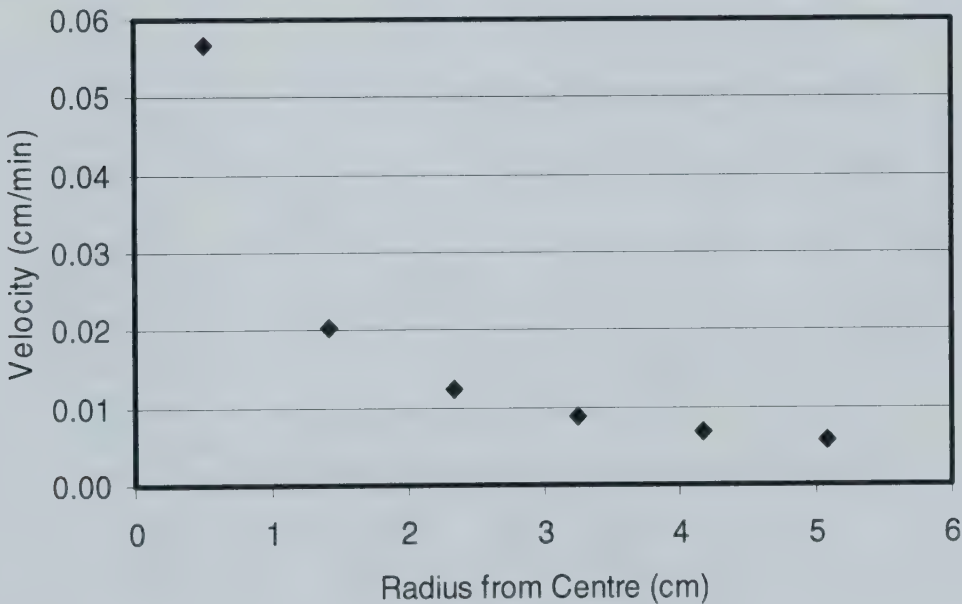


Figure 7-8: Velocity of the CGA fluid with respect to the radius of the radial sandpack.

The average velocity in the radial sandpack was 0.018 cm/min and occurred at a radius of 1.61 cm from the center of the sandpack.

On the other hand, the fluid velocity in the linear sandpack will be constant. It can be selected to lie within the range of fluid velocities that occurred within the radial sandpack. The injection rate for the linear sandpack will then be calculated from:

$$Q = V \cdot \pi r^2$$

7-1

where Q is the flow rate, V is the velocity and r is the radius of the sandpack.

Figure 7-9 shows the calculated flow rates for the corresponding velocities. The greatest flow rate corresponds to the point at the smallest radius in the radial sandpack (at the center of the radial sandpack). The range of flow rates available for the linear sandpack were between 4 and 44 cc/hr. In order to minimize the injection time, a rate of 44 cc/hr (0.73cc/min) was chosen for the linear sandpack experiment. This rate was kept constant throughout the experiment

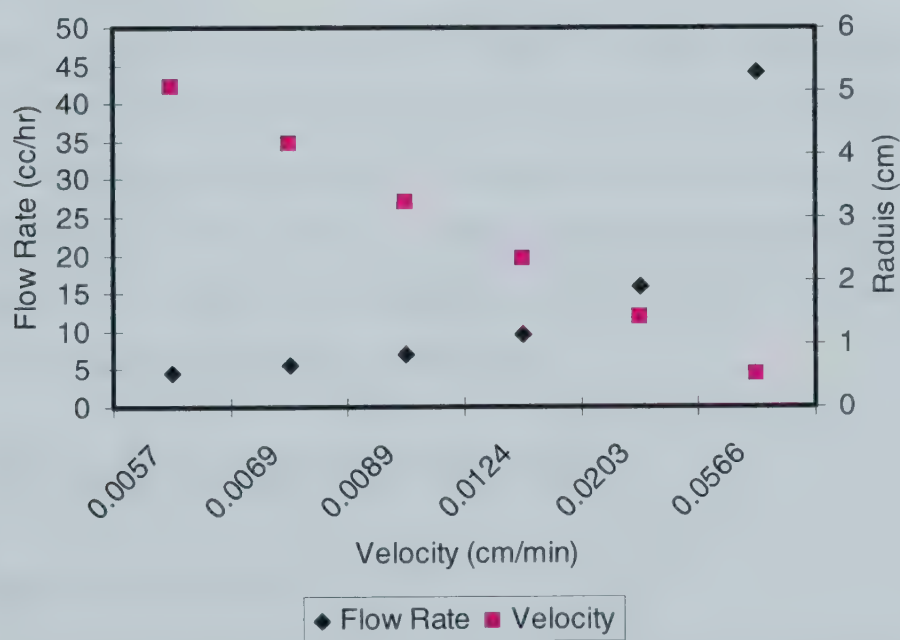


Figure 7-9: Range of flow rates for the linear sandpack experiment

After approximately 2L of CGA injection, the CGA fluid in the accumulator needed to be replenished. The injection of fluid was stopped by shutting off the pump and closing all the valves then more fluid was placed in the injection accumulator. Once the fluid was in the accumulator, the accumulator was repressurized back to the pressure of the sandpack before it was shut-in, the valves were re-opened and the test was continued. Care was taken during this process to ensure that no additional air was introduced to the system.

7.2.2.2.4 Re-injection of Saturation Fluid

Water was re-injected into the sandpack after the approximate maximum pressure with the CGA fluid was reached. This was done to determine how easily the CGA fluid could be removed from the system and also to get an indication of the residual permeability. The fluid was injected through the injection line and at the same rate as the CGA fluid until a constant minimum pressure was reached. Minimum pressure is defined as the point where there was an insignificant change in the pressure gradient for an extended period of time during water injection.

7.2.2.2.5 CT Scanning

At intervals throughout the injection of fluids, CT scans were obtained of the sandpack. This was done to obtain information about the distribution of fluid saturation throughout the sandpack. CT scans were taken of the dry sandpack before injection, the water saturated sandpack, the sandpack after the maximum pressure with CGA injection was obtained and the sandpack after the minimum pressure was obtained with water re-injection.

7.3 COREFLOW EXPERIMENTAL RESULTS

7.3.1 Radial Sandpack Study

Tests were conducted at different flow rates, CGA formulation, saturation fluids, permeability and wettability.

7.3.1.1 Effect of Flow Rate

Figure 7-10 indicates the effect of flow rate on the CGA injection pressure. When the flow rate was increased from 3 cc/min to 4 cc/min, the maximum injection pressure per meter increased from approximately 9300 kPa/m to 10200 kPa/m. However, even though the flow rate was increased by one-third, the pressure drop did not increase by one-third. This implies that the resistance to CGA flow decreased.

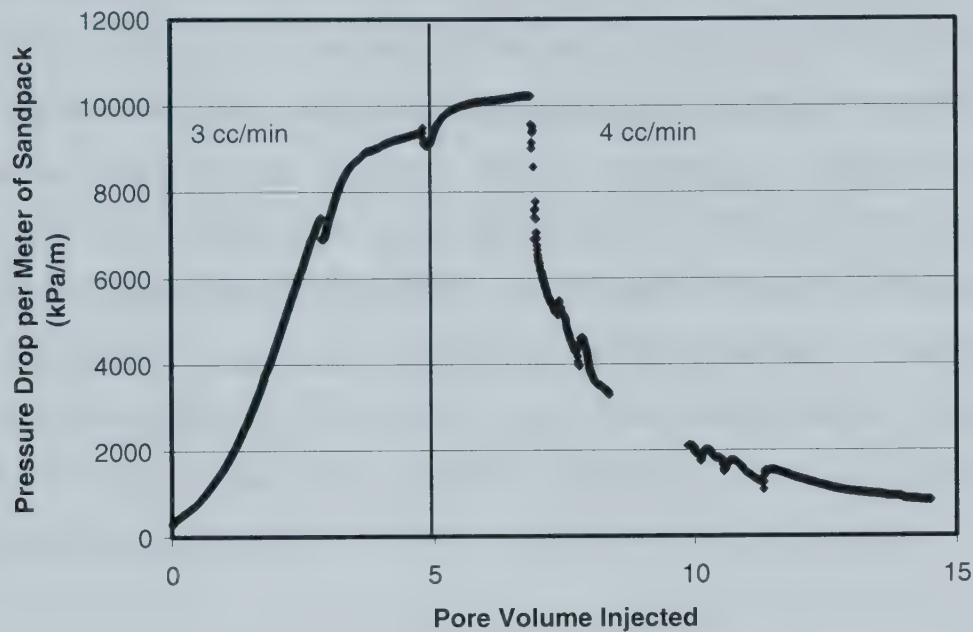


Figure 7-10: Experimental data for a change in flow rate from 3 cc/min to 4 cc/min (B-P2-S2-R3-k3 and B-P2-S2-R4-k3).

7.3.1.2 Effect of Fluid Composition

Figure 7-11 shows the results from the experiments with three different CGA formulations: one without any polymer (W-P0-S2-R3-k3), one without any surfactant (W-P2-S0-R3-k3) and one with both polymer and surfactant (W-P2-S2-R3-k3). The highest pressure gradient was observed when both polymer and surfactant were used (W-P2-S2-R3-k3). The approximate maximum pressure drop per meter was 9,600 kPa/m for this experiment compared to 2,500 kPa/m and 420 kPa/m for the experiment without surfactant (W-P2-S0-R3-k3) and for the experiment without polymer (W-P0-S2-R3-k3) respectively. Without any polymer (W-P0-S2-R3-k3), the CGA is not very stable and cannot last over a long period of time. This is evident from the rise and fall of pressure gradient between 0 and

2 PV of injection. When comparing the experiment with both polymer and surfactant (W-P2-S2-R3-k3) to the experiment without surfactant (W-P2-S0-R3-k3), we can see the blocking effect of the CGAs indicated by the increasing pressure drop across porous media as more CGA fluid is injected. No CGAs were generated when there was no surfactant in the formulation. Without CGAs present the rise in pressure gradient was much less. This is different from the results presented in Chapter 6. There the pressure drop per unit length was higher at lower surfactant concentrations, the pressure gradient was greater (Figure 6-28). In the micromodel experiments however, a micromodel with a very small pore volume was used and the highest possible pressure drop across the micromodel could not be achieved due to the pressure limitations of the micromodel. Since these tests were conducted in a sandpack with much larger pore volumes and a maximum pressure was reached, it can be concluded that the results obtained for the sandpack experiments are more realistic. As well, for the micromodel experiments the flow rate was 3 Pore Volumes/min. compared to 0.006 Pore Volumes/min for the coreflood experiments. The large difference in flow rates makes a comparison of the two sets of experiments difficult.

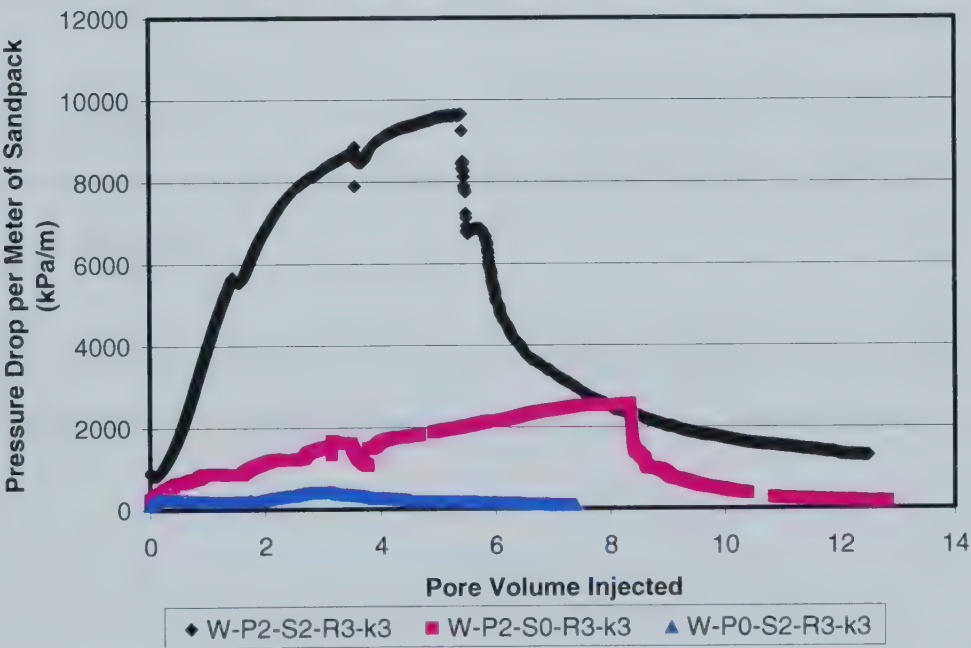


Figure 7-11: Effect of polymer and surfactant concentration in the CGA formulation

7.3.1.2.1 Assessment of Formation Damage

Figure 7-12 shows a comparison of the pressure drop due to flow of water through the sandpack prior to CGA injection (baseline) to the pressure drop due to flow of water through the sandpack after CGA injection. For each experiment, the sand pack is initially saturated and flushed with water and the pressure drop is recorded as the “base line pressure drop”. Then, the sand pack is flooded with the CGA test fluid. After that the sand pack is flushed with water again and pressure drop is measured as the “final pressure drop”. The difference between the “base line pressure drop” and the “final pressure drop” is considered as an indication of the formation damage due to the test fluid flow used in the particular experiment.

The experiment using a CGA formulation of both polymer and surfactant (W-P2-S2-R3-k3) had the most formation damage since the difference between “baseline pressure drop” and the “final pressure drop” was the highest in this case. After injecting 7 PV, the pressure gradient in the sandpack was still 1250 kPa/m greater than the baseline water pressure gradient. Although the final pressure drop did not return to the baseline pressure drop, a noticeable reduction in pressure gradient was recorded once the saturation fluid (i.e. water) was re-injected, approximately 8300 kPa/m (Figure 7-11).

When only polymer was used for the CGA formulation (W-P2-S0-R3-k3), the final pressure drop was 125 kPa/m greater than the baseline pressure drop after 4 PV of water injection.

There is very little difference in pressure drop observed between the baseline pressure drop and the final pressure drop when only a surfactant/water mixture is used.

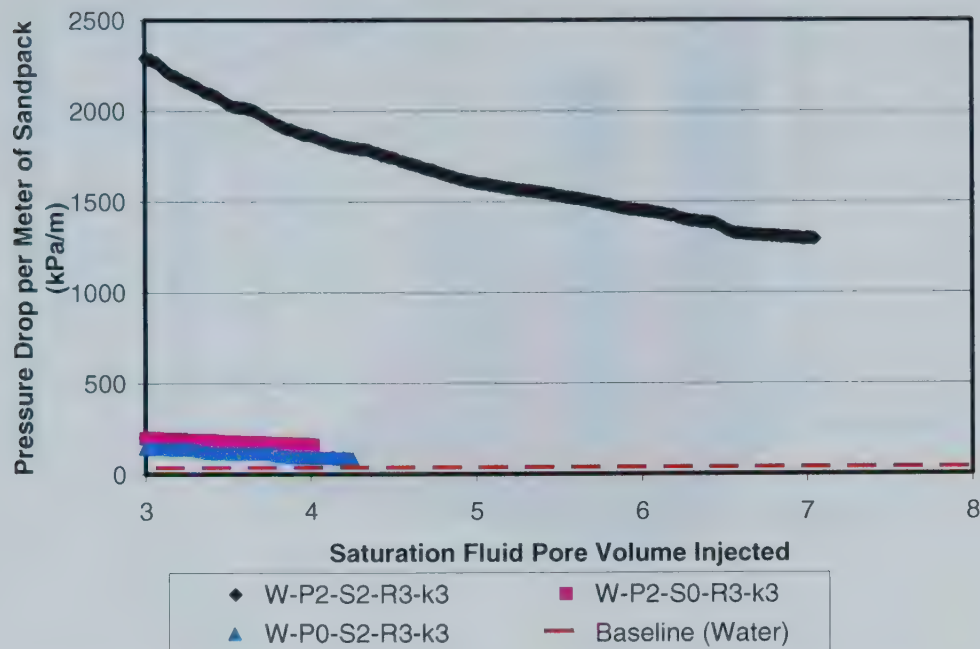


Figure 7-12: Comparison of the saturation fluid pressure drop after CGA injection to the baseline pressure drop before CGA injection

The approximate change in permeability due to CGA fluid flow across the sand pack is calculated by multiplying original permeability of the sand pack with the ratio of “final pressure drop” to “baseline pressure drop”. Results are shown in Figure 7-13. The original permeability of the sandpack before CGA injection was 3 D. The approximate permeability gives an indication of the formation damage produced by the CGA fluid. The greater the reduction in the approximate permeability from the original 3 D, the greater the formation damage. The figure shows the approximate permeability after 2 and 4 PV of re-injected formation fluid (i.e. water). It also shows the approximate permeability after the test was completed. It is evident that the experiment conducted without any polymer (W-P0-S2-R3-k3) shows the least amount of formation damage with an approximate permeability of 1.2 D after slightly more than 4 PV of reservoir fluid re-injection. The experiment with a CGA formulation of both polymer and surfactant (W-P2-S2-R3-k3) had an approximate permeability of less than 0.2 D after 7 PV of re-injection of the saturation fluid.

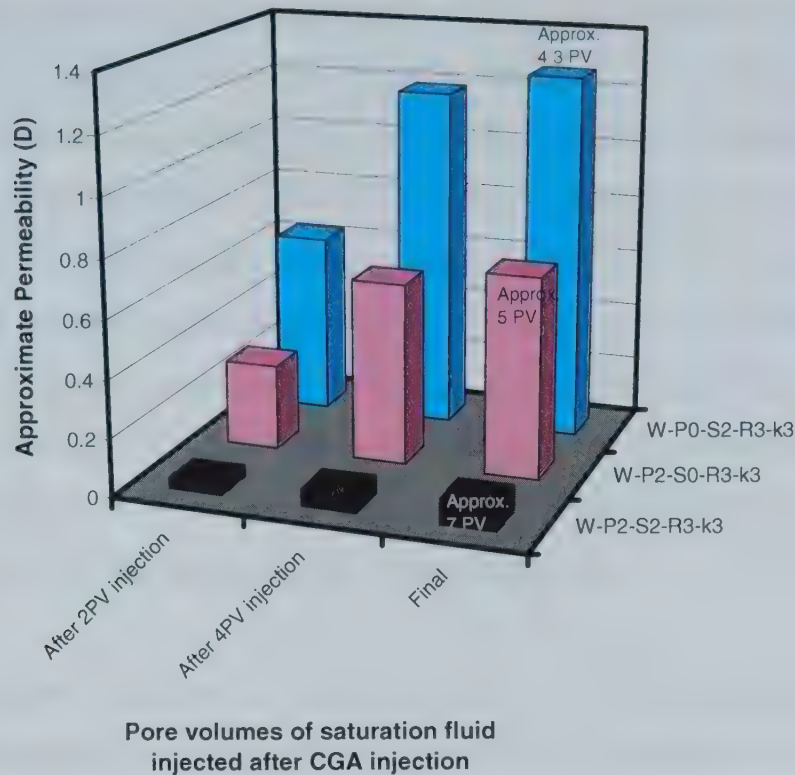


Figure 7-13: Approximate permeability of sandpack after re-injection of the saturation fluid.

7.3.1.3 Effect of Saturation Fluid Type

Figure 7-14 compares the results of experiments when water and brine were used as saturation fluids. Both experiments have very similar increase in pressure drop for the period of the CGA injection. In the experiment with brine as the saturating fluid, there is an additional increase in pressure drop due to a flow rate increase from 3 to 4 cc/min around 5 PV of injection. The results indicate that brine as a saturation fluid has little effect on the pressure drop due to CGA flow in the sandpack when compared to the pressure drop due to CGA flow in a sandpack initially saturated with water.

The results from the experiments with mineral oil and water as saturation fluids are compared in Figure 7-15. As with Figure 7-14, the increase in pressure drop was similar in both experiments. However the maximum pressure reached was different. A slightly higher pressure drop occurred in the sandpack saturated with mineral oil. Since mineral oil is more viscous than water (80 cP), it requires a greater pressure gradient to move at the same velocity through the same porous

medium. Similar results were also obtained with the micromodel experiments. The experiment with mineral oil as the saturation fluid (MO-P2-S2-R3-k3) is also the best example of how replenishing the accumulator can effect the pressure drop in the sandpack. From Figure 7-15 we can see a great increase in pressure after approximately 11 PV. This occurred immediately after the valves to the sandpack were closed and the saturation accumulator was replenished with fluid. Since mineral oil was being re-injected at this point, one should be expecting a decrease in the injection pressure. Instead there is a large increase in the pressure drop. This possibly indicates how the accumulator replenishment can drastically affect the pressure drop in the sandpack once the flow is resumed.

Figure 7-16 compares the effect of water to crude oil as the saturation fluid. It shows that the increase in pressure drop with crude oil is slightly less than the pressure drop with water. After 5 PV of CGA fluid injection, the pressure drop in the sandpack is 18% less in the crude oil case than in the water case. This may be due to the stability of the CGA fluid when it is in contact with crude oil. Although the instability of CGAs was not detected during micromodel fluid flow, Hanssen and Dalland (1990) and Manlowe and Radke (1990) found that the

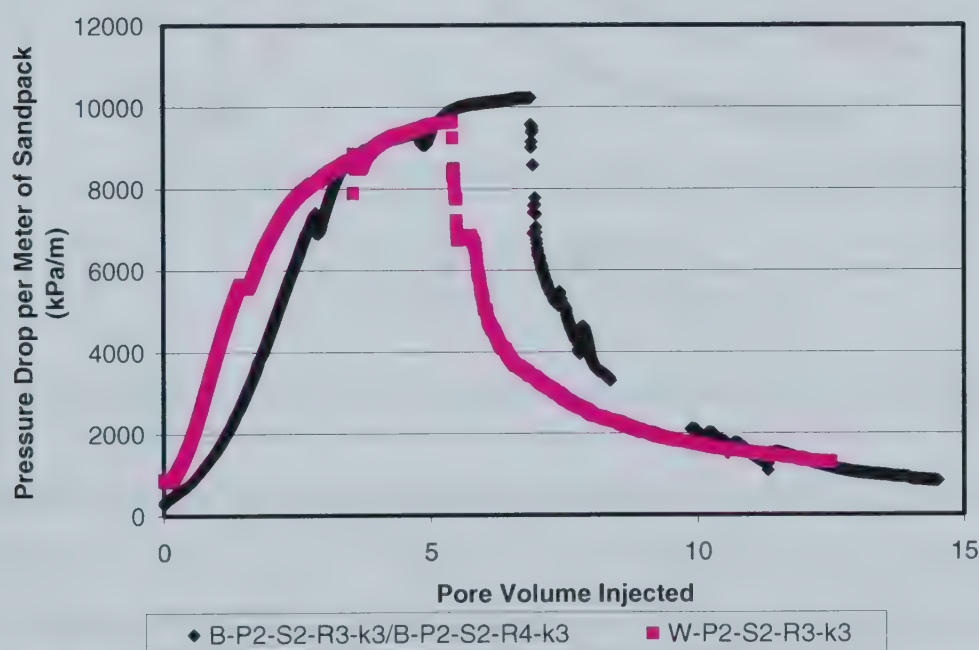


Figure 7-14: Effect of brine as the saturation fluid when compared to water as the saturation fluid.

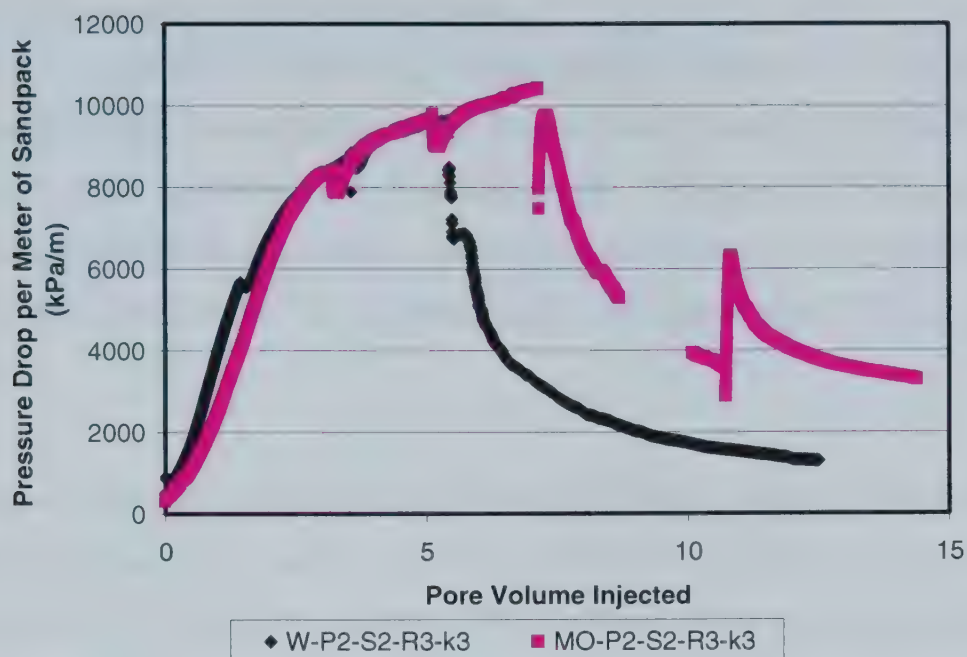


Figure 7-15: Effect of mineral oil when compared to water as the saturation fluid.

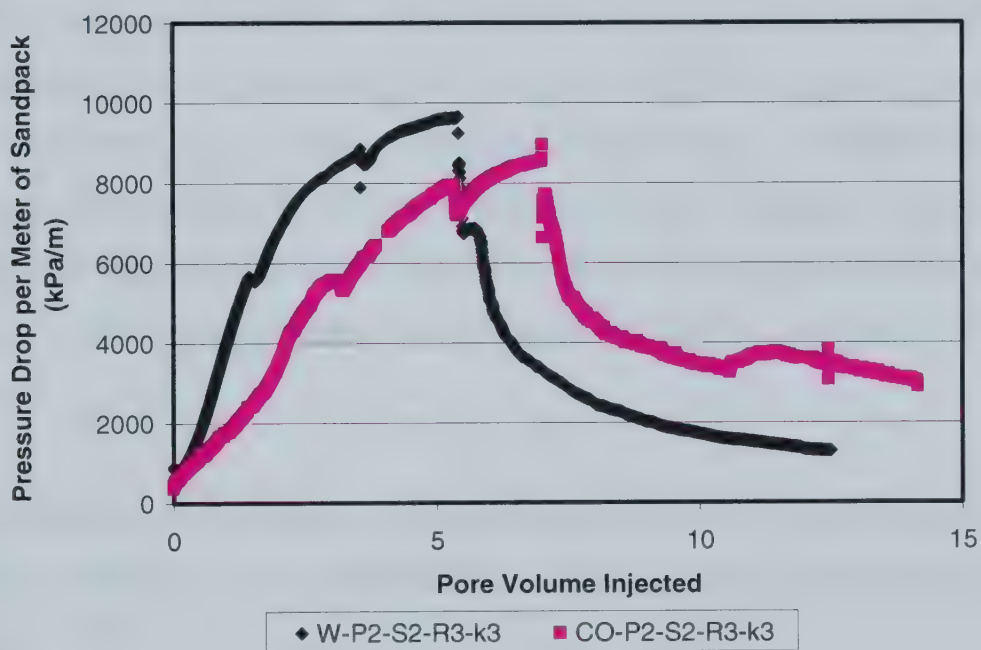


Figure 7-16: Effect of crude oil when compared to water as the saturation fluid.

stability of foams are in question when in contact with crude oil. Since the tests presented here have a greater PV than the micromodel tests, there is likely more contact between the CGAs and the crude oil which may result in some crude oil influence on the CGA stability.

7.3.1.3.1 *Assessment of Formation Damage*

Figure 7-17 compares the pressure gradient with the saturation fluid before CGA injection (baseline pressure drop) to the final pressure gradient with the saturation fluid after CGA injection (final pressure drop). When water was used as the saturation fluid (W-P2-S2-R3-k3), the difference between the baseline and final pressure drops with water was approximately 1300 kPa/m after 7 PV of water re-injected.

When brine was used as the saturation fluid (B-P2-S2-R30k3/B-P2-S2-R4-k3) the difference between the baseline and final pressure drop was approximately 800 kPa/m after 8 PV of brine re-injected. The flow rate of the water experiment was 3 cc/min and the flow rate of the brine experiment was 4 cc/min. The difference in flow rate may have an effect the ability of the saturation fluid to remove the CGA fluid from the sandpack during re-injection.. As well, it should be noted however, that for all experiments that included a saturation fluid other than water, the accumulator was replenished after around 4 to 5 PV of injection. As a result of this, the valves to the sandpack were closed and flow of saturation fluid was terminated for a short period of time. This can result in a disruption of flow and a disruption of the sandpack which may have an effect of the pressure drop in the sandpack. Therefore, although comparisons are made, they are made with caution.

The minimum pressure drop per unit length achieved after re-injection of mineral oil as the saturation fluid was 2600 kPa/m more than that of the baseline pressure drop after 7 PV.

The final minimum pressure gradient achieved after 7 PV of injection for crude oil was 2600 kPa/m more than the baseline pressure gradient.

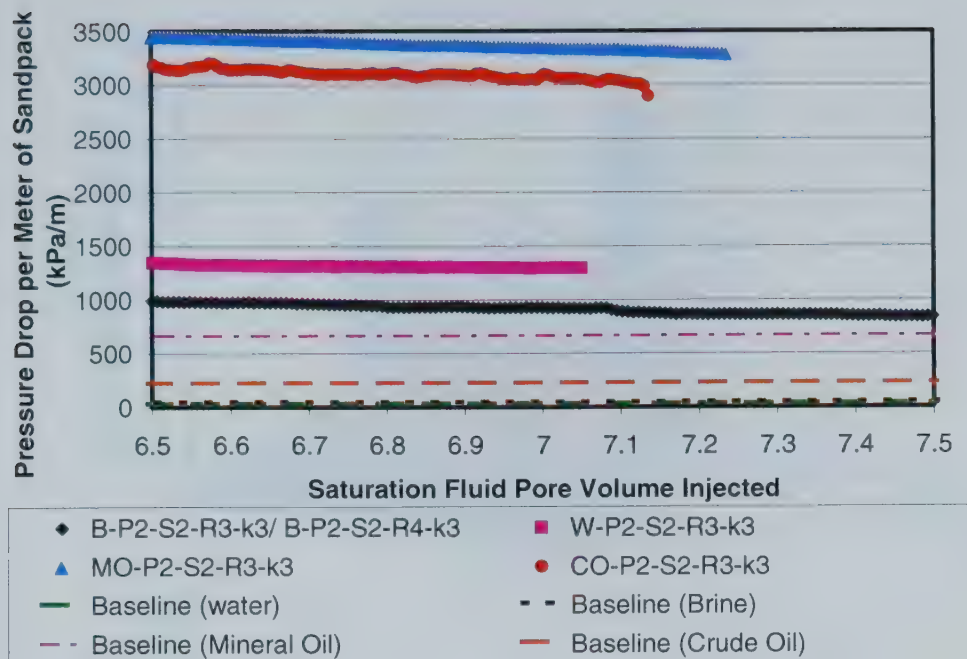


Figure 7-17: Comparison of the saturation fluid pressure drop after CGA injection to the baseline pressure drop before CGA injection

The approximate permeability of the sandpack during the reservoir fluid re-injection is given in Figure 7-18. The original permeability of the sandpack before CGA injection was 3 D. The figure shows the approximate permeability after 2 and 4 PV of re-injected formation fluid and the approximate permeability after the test was completed. It is evident that the experiment conducted with mineral oil as the saturation fluid (MO-P2-S2-R3-k3) shows a lesser amount of formation damage with an approximate permeability of more than 0.5 D after 7 PV of reservoir fluid re-injection. This is compared to the experiment with crude oil as the saturation fluid (CO-P2-S2-R3-k3) which had an approximate permeability of 0.2 D after 8 PV of re-injection of the saturation fluid and the experiments with brine (B-P2-S2-R3-k3/B-P2-S2-R4-k3) and water (W-P2-S2-R3-k3) which had an approximate permeability of 0.2 D and 0.1D after 8 and 7 PV of re-injection of the saturation fluid.

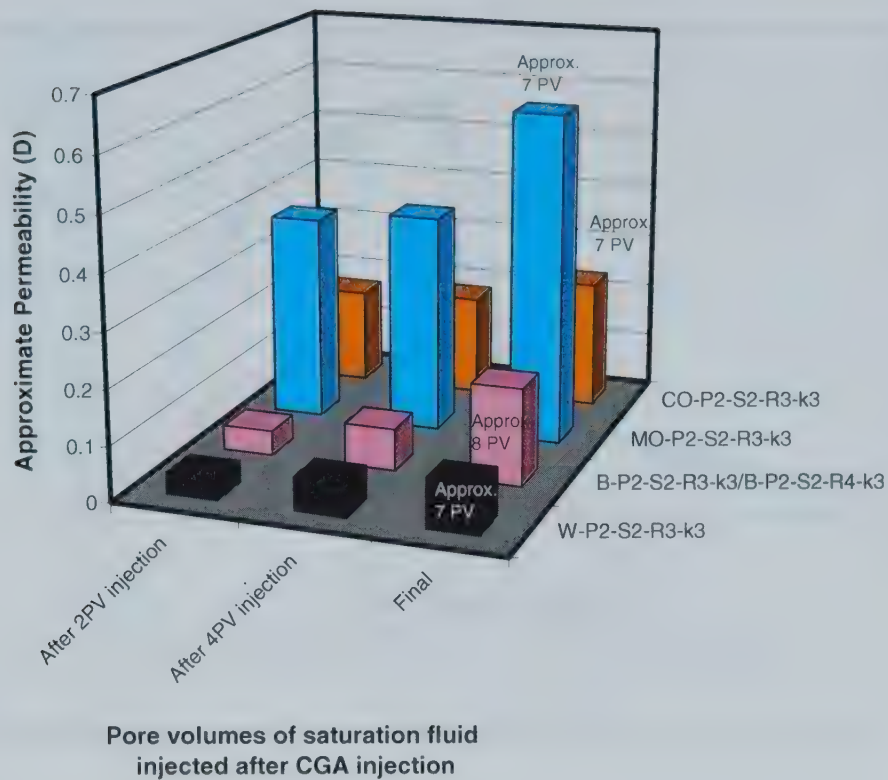


Figure 7-18: Approximate permeability of sandpack after re-injection of the saturation fluid.

7.3.1.4 Effect of Permeability

Results of the CGA fluid flow experiments conducted by using sandpacks with different permeability are shown in Figure 7-19. The sandpack with the greater permeability (42D) (B-P2-S2-R3-k42) has a slower increase in pressure drop than the experiment with the lower permeability (3D) (B-P2-S2-R3-k3/B-P2-S2-R4-k3). This can be attributed to the fact that larger pore sizes in high permeability sand pack would require more microbubbles to accumulate in order to restrict the flow and hence, cause the rate of pressure drop increase. The maximum pressure gradient for the 42 D sandpack was almost 4000 kPa/m compared to a maximum pressure gradient for the 3 D sandpack of more than 9000 kPa/m (at 3 cc/min).

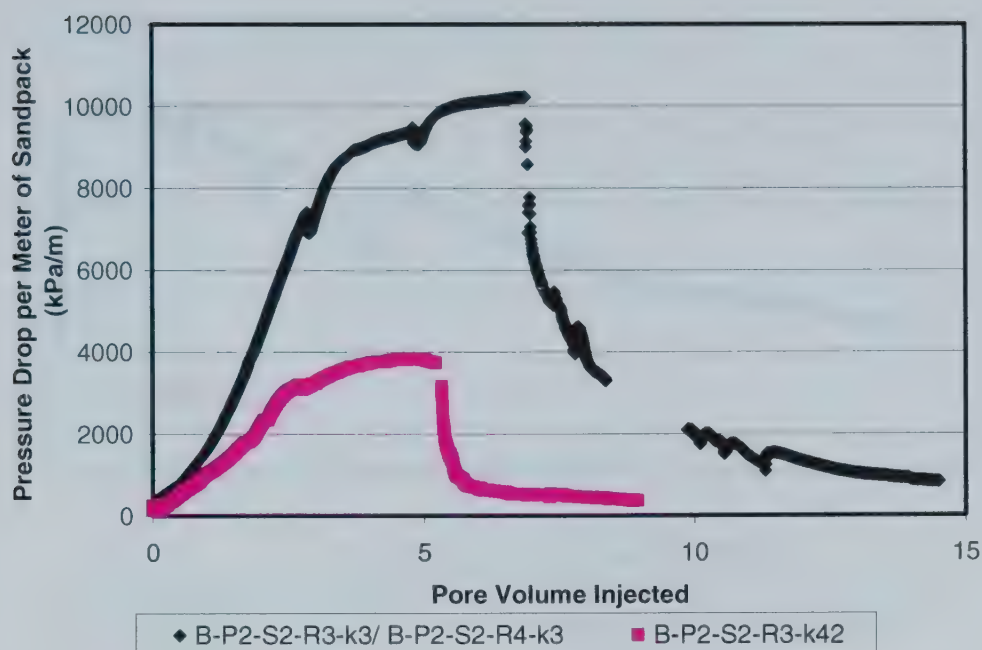


Figure 7-19: Effect of permeability on the pressure rise in the sandpack

7.3.1.4.1 Assessment of Formation Damage

Figure 7-20 compares the pressure gradient with saturation fluid before (baseline pressure drop) and after (final pressure drop) CGA injection for both permeabilities. With the lower permeability, difference between the baseline pressure drop and final pressure drop with brine injection is approximately 800 kPa/m. For the higher permeability case, the change between the baseline and final pressure gradient is approximately 360 kPa/m.

The approximate permeability of the sandpack after CGA injection and during the reservoir fluid re-injection is given for both the high (42D) and low (3D) permeability case in Figure 7-21. It shows that the reduction in permeability is greater in the low permeability case than in the high permeability case.

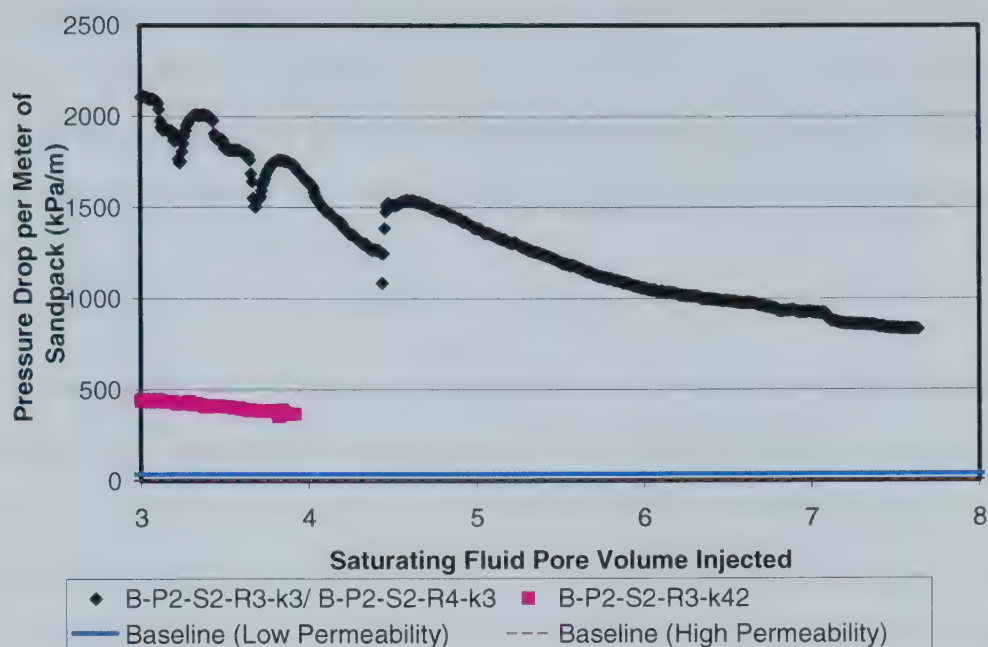


Figure 7-20: Comparison of the saturation fluid pressure drop after CGA injection to the baseline pressure drop before CGA injection

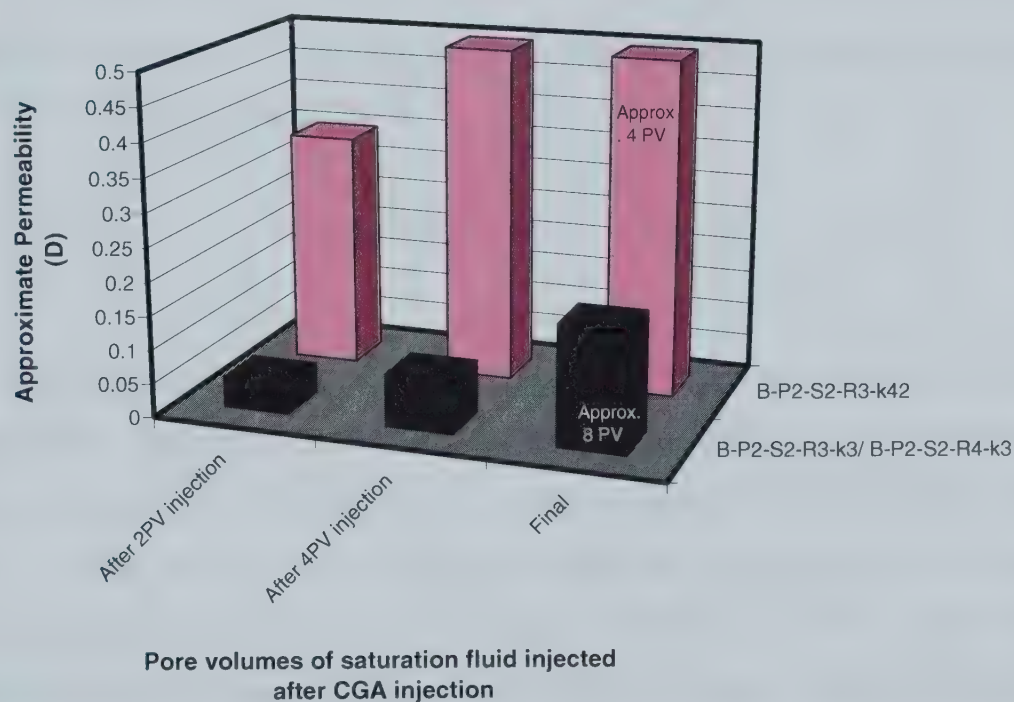


Figure 7-21: Approximate permeability of sandpack after re-injection of the saturation fluid.

7.3.1.5 Effect of Wettability

Experiments were conducted using sandpacks prepared with water-wet and oil-wet sands. The wettability of the sand was changed by treating the sand with a

silanization agent to make the sand oil-wet. Figure 7-22 shows the difference between the original water-wet sand and the treated sand when immersed in water. The untreated sand (Figure 7-22a) disperses throughout the water evenly whereas the oil-wet sand (Figure 7-22b) clumps together on the surface of the water showing that it is hydrophobic.

Once the sand was treated, it was packed into the sandpack vessel and saturated with mineral oil. The experimental results for the two different sands are given in Figure 7-23. One can see that there is a drastic difference between the water-wet sand and the oil-wet sand. The increase in pressure drop in the oil-wet sand is almost 3 times less than the increase in pressure drop in the water-wet sand. In the water-wet or hydrophilic case, the CGA fluid will have a greater tendency to remain at the pore bodies since the fluid is composed of water whereas in the oil-wet or hydrophobic case, the CGA fluid will have a greater tendency to pass through the pore bodies. The difference in pressure can be explained with the capillary pressure equation given by:

$$P_c = \frac{2\gamma\cos\theta}{r} \quad 7-2$$

Where γ is interfacial tension, θ is the contact angle and r is the radius of the capillary tube. Since both the hydrophilic and hydrophobic cases have the same fluids (ie polymer with air bubbles), the interfacial tension of both systems will be similar. As well, we can assume that that radius for both cases will be similar since the sand grains are of similar dimension. Therefore, only the contact angle will differ between the hydrophilic and hydrophobic cases. In the hydrophilic case, the contact angle will be very close to 0° since the water fully wets the capillary tube. In the hydrophobic case the contact angle will be greater than 0° . With all other factors being equal, this change in contact angle from the hydrophilic case to the hydrophobic case will reduce the capillary pressure.

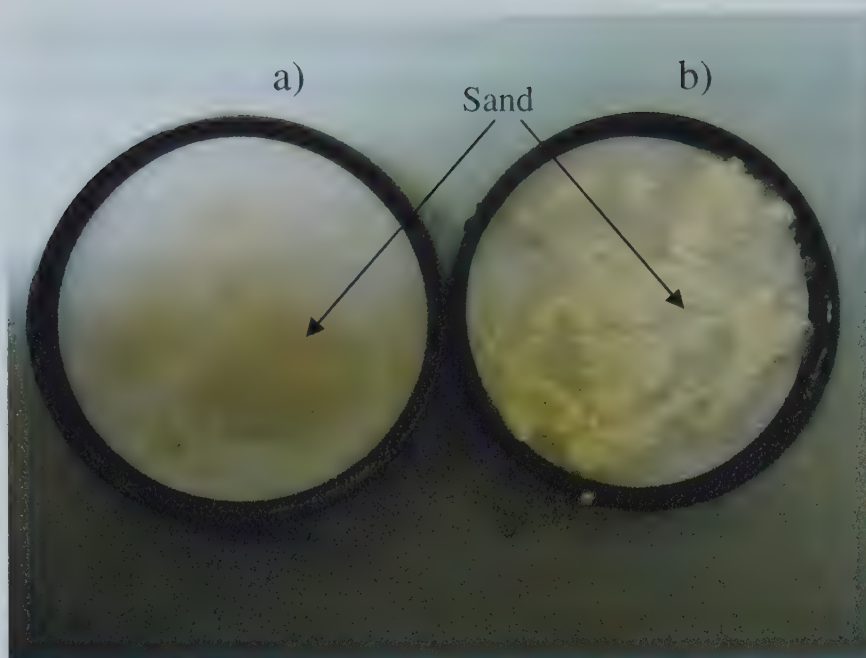


Figure 7-22: Comparison of oil wet and water wet sand immersed in water.

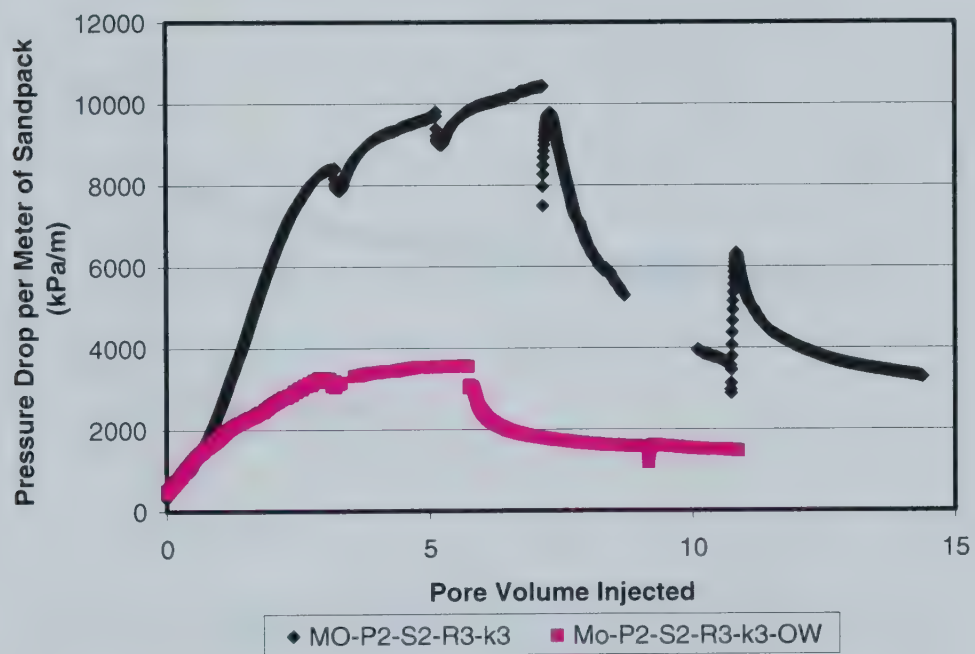


Figure 7-23: Effect of wettability of the pressure rise in the sandpack.

7.3.1.5.1 Assessment of Formation Damage

Figure 7-24 shows the difference between the pressure gradient before and after CGA injection for the water-wet and oil-wet sand. The difference in pressure gradient is greater for the water-wet case (2600 kPa/m after 8 PV) than it is for the oil-wet case (800 kPa/m after 5 PV) indicating that it is harder to remove the CGA fluid from the water-wet sand with mineral oil than it is to remove the CGA fluid from the oil-wet sand.

Figure 7-25 shows that the approximate permeability of the sandpack after re-injection of the saturation fluid is much higher for the oil-wet sand than it is for the water-wet sand. Once again, this indicates that the CGA fluid is easier to remove from the oil-wet sand than from the water-wet sand.

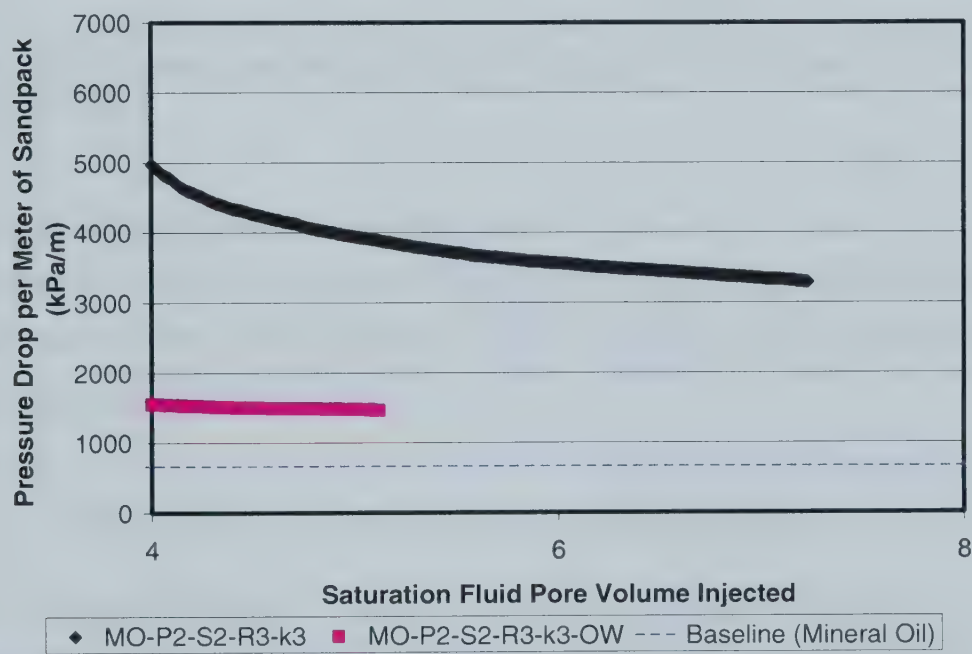


Figure 7-24: Comparison of the saturation fluid pressure drop after CGA injection to the baseline pressure drop before CGA injection

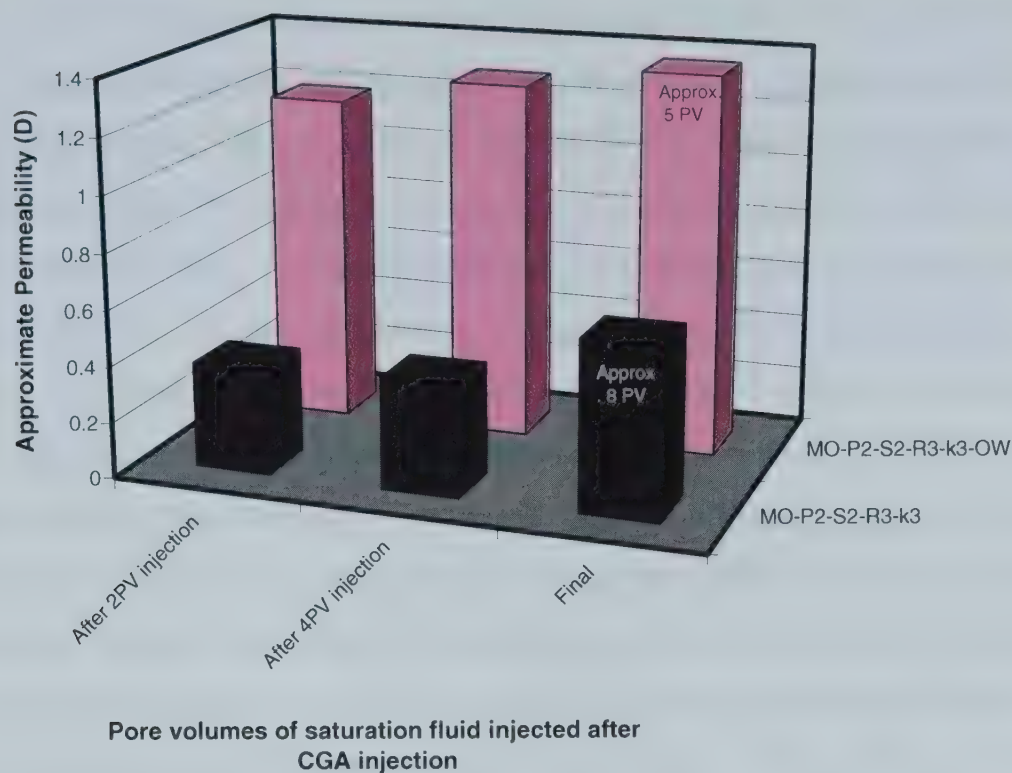


Figure 7-25: Approximate permeability of sandpack after re-injection of the saturation fluid.

7.3.1.6 Summary of Formation Damage

The percentage of residual permeability (i.e. percentage of original permeability that has been recovered after reservoir fluid re-saturation) of all the experiments is calculated by the following equation:

$$\text{Residual } k = (\text{Final Approximate } k / \text{Original } k) * 100 \quad 7-3$$

where k is permeability. Table 7-4 lists the residual permeabilities for the experiments conducted. The experiment with the oil-wet sand (MO-P2-S2-R3-k3-OW) resulted in the highest residual permeability of approximately 46%. The experiment with no polymer in the CGA formulation (W-P0-S2-R2-k3) had the second highest residual permeability of 42%. These residual permeability is much lower than what was found by Belkin et al. (2005) for CGA drilling mud. They calculated a residual permeability between 80 and 90% for their experiments. However, the experiments conducted by Belkin et al. (2005) were at a differential pressure of 500 psi or 3400 kPa. The results obtained in this study

were at a constant flow rate which resulted in a pressure that was always less than 3400 kPa. The difference in pressure would have an effect on the size of the CGA and the blocking ability. The experiments by Belkin et al. (2005) were conducted at a temperature of 65 °C and the experiments presented here were conducted at room temperature (22°C). High temperatures have been known to affect the stability of the CGA. Longe (1989) found that the CGAs unstable at temperatures above 65°C. Belkin et al. (2005) experiments were conducted on Berea sandstone which would indicate that the permeability of the sample was much less than the 3 D sandpack used in this experiment. The Berea sandstone would most likely have a smaller pore throat radius. This would increase the capillary pressure at the radius which may have an effect on the stability and size of the CGA. As well, other experimental conditions such as time frame of the experiment and direction of flow of the saturating (re-injection) fluid were different. Therefore, it is very difficult to compare the results of Belkin et al. (2005) to the results presented here.

Table 7-4: Residual permeabilities for the experiments conducted.

Experiment #	Saturation Fluid Type	Original Perm. (D)	Baseline Pressure Drop (kPa/m)	Final Pressure Drop (kPa/m)	Final Perm. (D)	Residual Perm. (% of Original Perm.)
B-P2-S2-R4-k3	Brine	3	50	831	0.18	5.9
W-P2-S2-R3-k3	Water	3	37	1290	0.09	2.9
W-P2-S0-R3-k3	Water	3	37	161	0.7	23.2
W-P0-S2-R3-k3	Water	3	37	88	1.27	42.3
MO-P2-S2-R3-k3	Mineral Oil	3	665	3280	0.61	20.2
CO-P2-S2-R3-k3	Crude Oil	3	227	2890	0.24	7.9
B-P2-S2-R3-k42	Brine	42	4	366	0.5	1.2
MO-P2-S2-R3-k3-OW	Mineral Oil	3	665	1460	1.36	45.5

7.3.2 *Linear Sandpack Study*

Primarily, the linear core flood experiment was conducted to validate previous experiments conducted in the radial flow apparatus. Figure 7-26 shows the pressure drop (kPa) per length (meter) with respect to pore volume injected for the linear sandpack. The pressure drop increased relatively fast as more CGA fluid injected into the sandpack, indicating that CGAs are effectively blocking the pores. From the figure it is evident that approximately 16 PV of CGA fluid was needed in order to reach a maximum pressure drop. After approximately 20 PV of CGA injection, the fluid injected was switched to water. 70 PV of water (approx. 10 L) was then injected into the sandpack. The pressure drop per meter decreased from 6500 kPa/m to 500 kPa/m within 10 PV of water injection. However, a decrease in pressure from 500 kPa/m to 200 kPa/m was obtained in the next 60 PV of water injection. The “base line pressure drop” which was originally recorded for water flow before CGA fluid injection was approximately 2 kPa/m. Final pressure drop due to flow of water after the core was flushed with CGA fluid never reached to the baseline pressure drop. The significant difference between baseline pressure drop and final pressure drop indicated that the CGA fluid was not fully removed from the linear sandpack. The residual permeability for this test was 1%. Similar results were observed with the radial apparatus in that the pressure drop with water before CGA injection was much less than the pressure drop with water after CGA injection. Thus the results of the linear sandpack tests were consistent with the results of the radial sandpack test.

CT scans of the linear sandpack were obtained at various intervals during the experiment. The CT scanner measurements are proportional to the density of the sandpack. The measurements are reported in CT units called Hounsfield units (HU). The magnitude of the Hounsfield unit indicates the density of the fluid. Water has a Hounsfield unit of 0 and air has a Hounsfield unit of -1000. Solid particles such as sand have a much higher HU, approximately 2500. Figure 7-27 shows the HU for the length of the sandpack (length was measured in image slices where the thickness of a slice is 0.5 mm) before water injection, after water

injection, after CGA injection and after water re-injection. Prior to the initial water injection, the sandpack was composed of air and sand and the HU reflects this with an average value of around 1000. Once water was injected into the pack, the HU increased to around 1400. This was expected since water is denser than air. After CGA injection the HU dropped to a value of around 1150. This occurs because the CGA fluid is composed of both liquid and air and the water that was once in the system has been replaced by the fluid/air of the CGAs. After water re-injection, the HU remained around 1150. This indicates that there was still an appreciable amount of CGA fluid in the sandpack. The exception to this was at the start of the sandpack (<50 slices) where the HU was greater indicating that there was more water in that section of the pack.

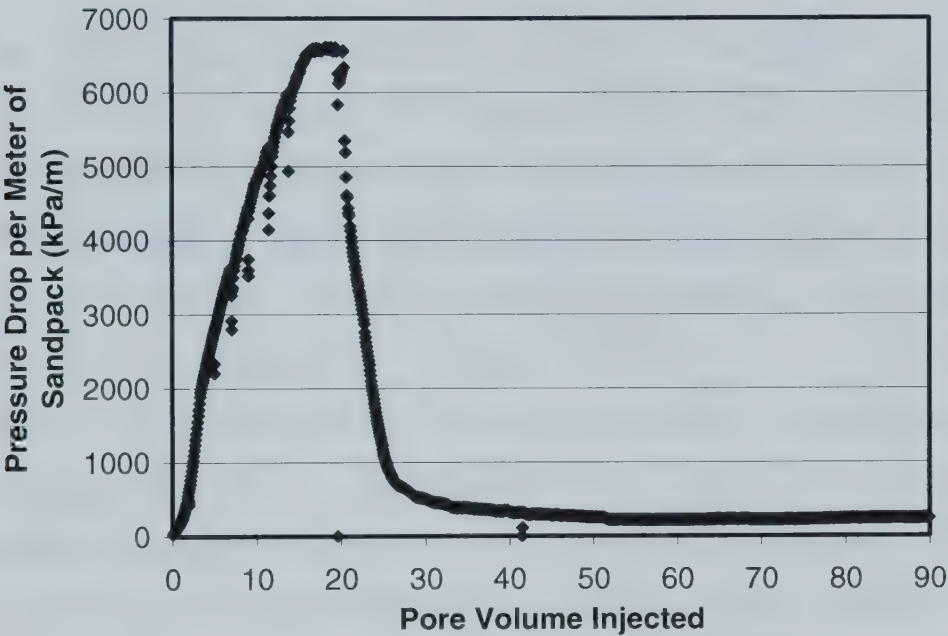


Figure 7-26: Results of the linear sandpack experiment

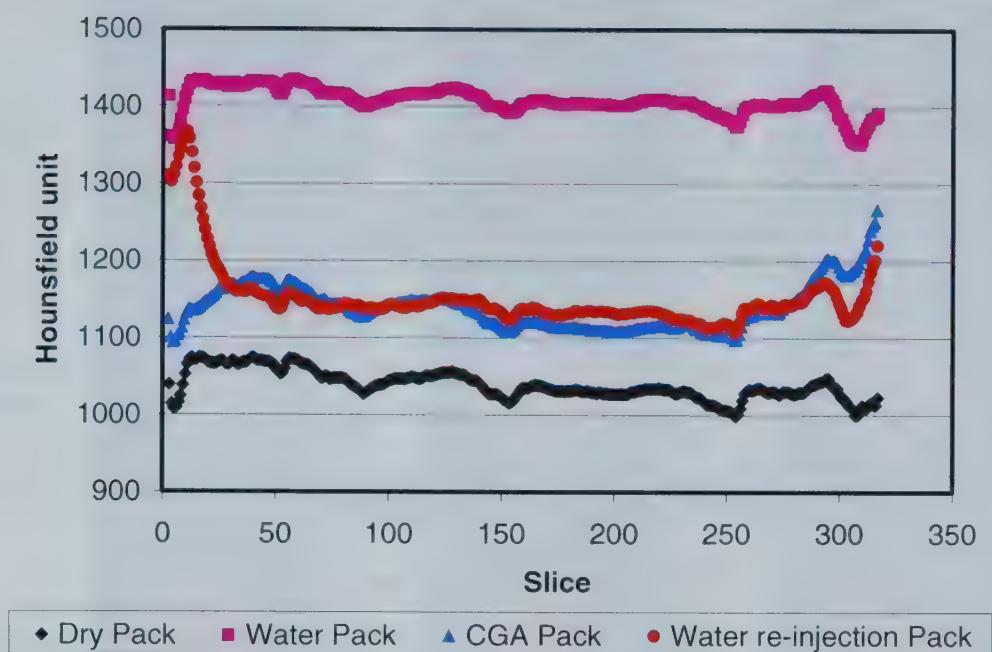


Figure 7-27: HU along the length of the sandpack

CT images of the sandpack are given in Figure 7-28. The images also show the change in HU with a change in fluid injection. For the dry pack, after water saturation and after CGA injection images, the HU was fairly constant throughout the entire length of the sandpack as indicated by the similar colour in each slice interval given in the figure. However, after water re-injection, it was evident that there is an area at the bottom of the sandpack with HU levels are above the rest of the sandpack. This persists along much of the length of the sandpack. The images indicate that there was water present in the area (same HU as the after water saturation images) and all other areas are still CGA saturated. The area where there was water present was largest at the start of the sandpack and the smallest at the exit of the sandpack. This indicates that during water re-injection gravity segregation occurred between the water and CGA fluid. Once water breakthrough occurred, the CGA fluid was no longer removed from the sandpack. Since the area where the water was present was small compared to the total cross sectional area of the sandpack, the pressure in the sandpack during water re-injection was higher than the pressure when there was only water present in the pack (before CGA injection).

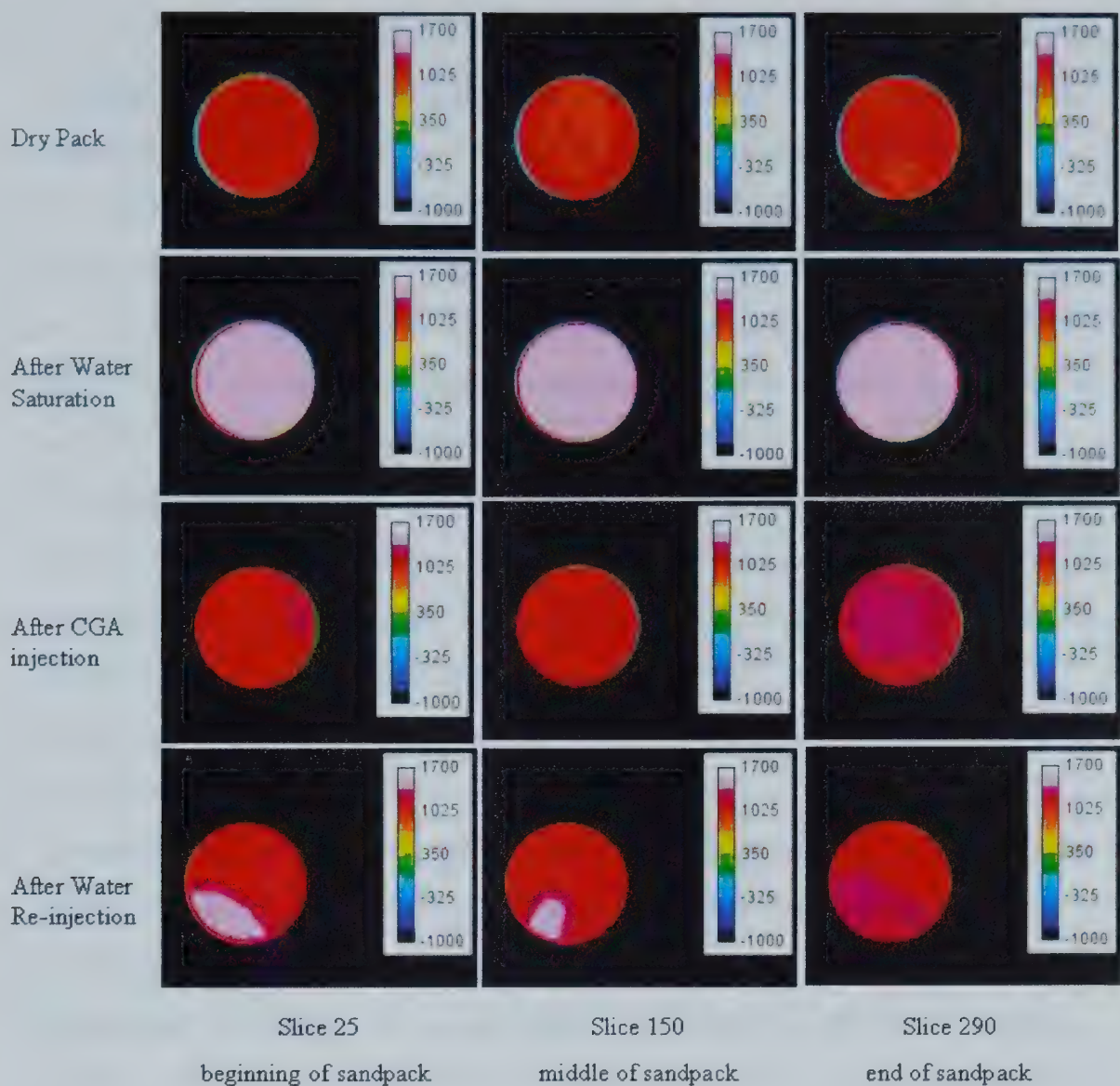


Figure 7-28: CT Scans of the sandpack at various stages during the experiment

7.4 SUMMARY

The following conclusions can be drawn from the sandpack experiments:

- Higher pressure drop through porous media was observed when flowing CGA fluids formulated by using both polymer and surfactant (as compared to the flow of fluids formulated with only polymer and only surfactant). Much higher resistance to CGA fluid invasion in this case indicates that both polymer and surfactant are needed for a stable CGA fluid.

- In most cases, the maximum pressure (i.e. pressure drop per unit length) required for injection of CGA fluid through porous media saturated with brine was similar to that of the case when water was used as saturation fluid.
- The maximum pressure required for injection of CGA fluid through porous media saturated with mineral oil was higher than that of the case when water was used as saturation fluid. This might be due to the fact that mineral oil has much higher viscosity than that of water although the increase in pressure is not proportional to the viscosity ratio.
- The maximum pressure required for injection of CGA fluid through porous media saturated with crude oil was lower than that of required for CGA fluid injection when water was used as saturation fluid. This may be due to the instability of CGA's in the presence of crude oil.
- Lower permeable sandpacks resulted in a more rapid increase in pressure drop and greater blocking ability.
- Wettability of the porous medium has a significant effect on the blocking ability of CGA's. CGA's block more efficiently in water-wet situations.
- CT images of the linear sandpack indicate that substantial amounts of the CGA fluid was present in the sandpack after more than 60 PV of water re-injection. The images also indicate that there was gravity segregation between water and the CGA fluid.
- When comparing the pressure drop in the sandpack with water injection before and after CGA injection, the pressure after CGA injection was more than 200 times more than the pressure before CGA injection, indicating the CGA fluid was present in the sandpack after water injection.
- The results of the linear sandpack test are consistent with the results of the radial sandpack tests.

8 NUMERICAL MODEL FOR PREDICTION OF COLLOIDAL GAS APHRON BUBBLE SIZE

This chapter outlines a methodology for numerical estimation of CGA bubble size. Figure 8-1 illustrates the different type of CGA models that need to be considered over a range of typical drilling conditions. The following activities were undertaken:

- CGA generation and stability models were investigated.
- Models for predicting bubble size at surface conditions were studied.
- Using bulk phase PVT data, the equations of state for CGA fluids were developed.
- A CGA-pore blocking prediction model was developed.

8.1 CGA MICROBUBBLE DIAMETER PREDICTION

In the past, bubble size has been theoretically determined by using stability (drainage) (Amiri and Woodburn, 1990) and bubble break-up models (Parthasarathy et al., 1991). Jauregi et al. (2000) summarized both of these models for CGAs.

8.1.1 Bulk Fluid Drainage Model (Amiri and Woodburn (1990) and Jauregi et al. (2000))

In the liquid drainage rate theory, the CGA bubble diameter is calculated using Stoke's expression.

$$d = \sqrt{\frac{18 \times \mu_w \times v_s}{(\rho_w - \rho_a) \times g}} \quad 8-1$$

where μ_w is the viscosity of the water or liquid phase, g is the gravitational coefficient, v_s is the settling velocity of the CGA in stagnant water, ρ_w is the

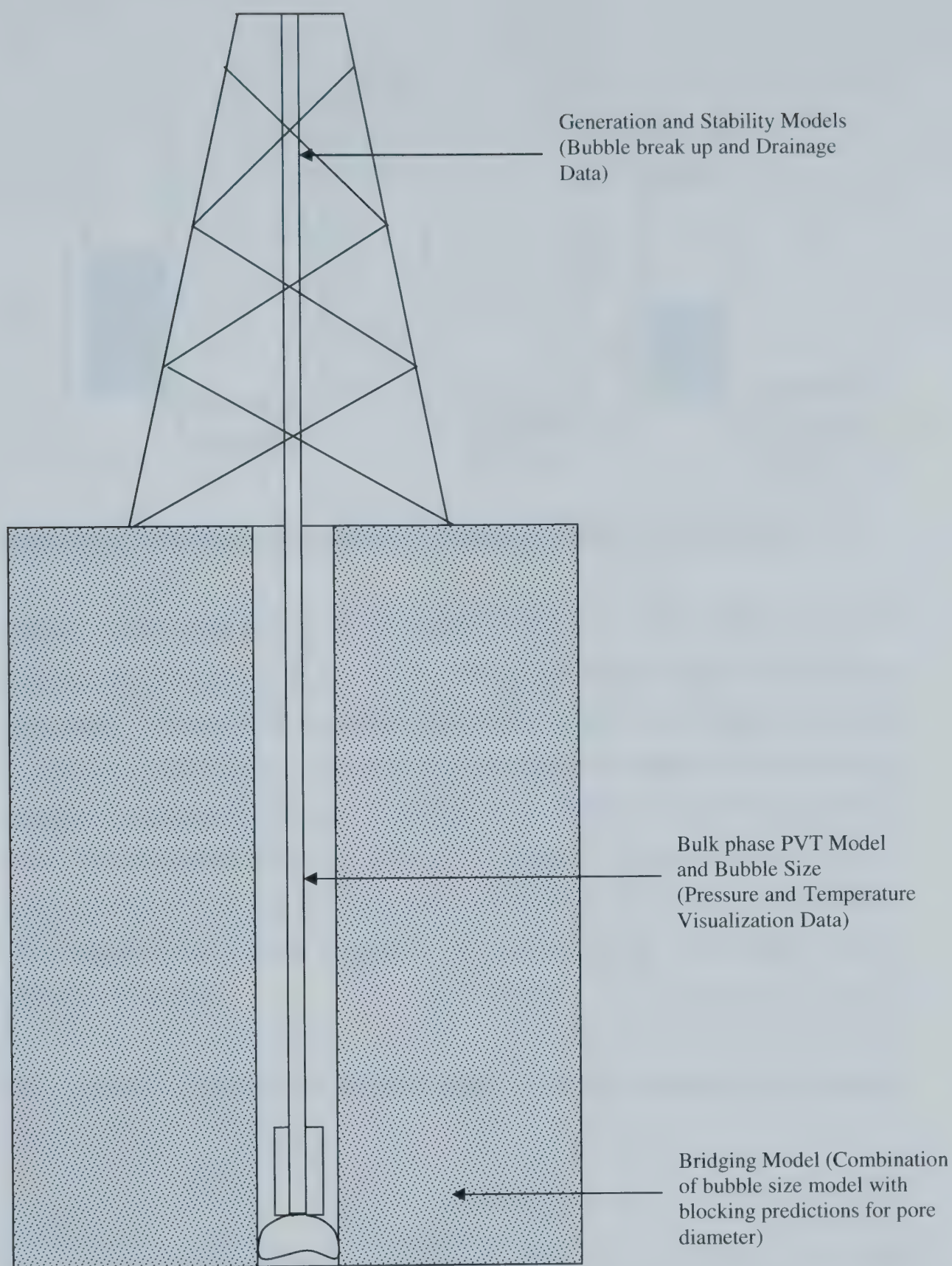


Figure 8-1: Diagram of prediction model flow

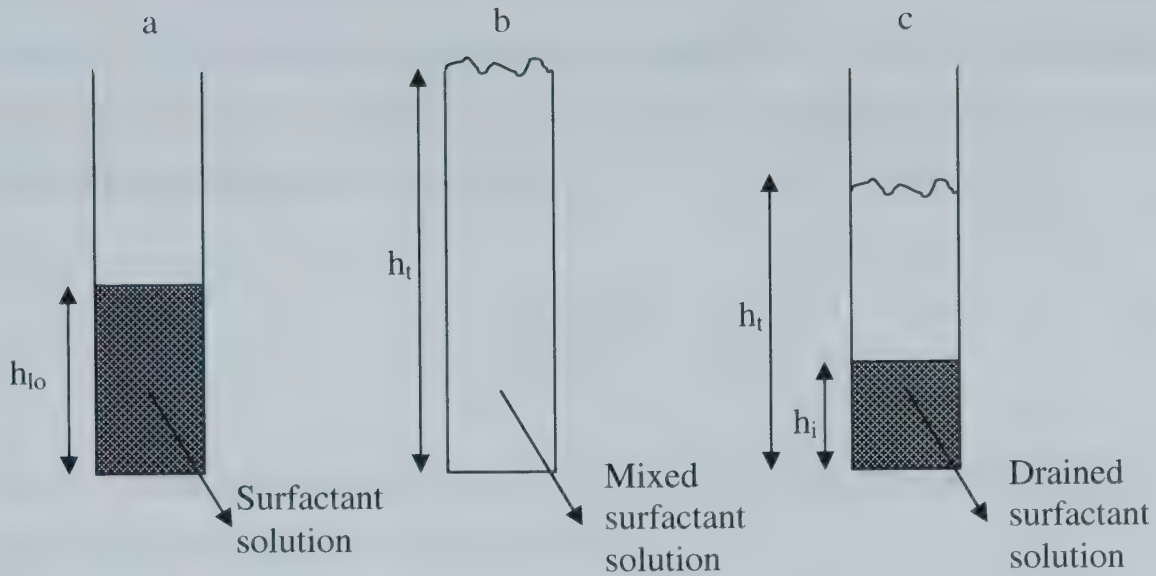


Figure 8-2: Drainage process for CGA dispersion (After Jauregi et al.2000)

density of the water and ρ_a is the density of the CGA. The process of liquid drainage is illustrated in Figure 8-2. A 250 ml graduated cylinder was used for this study. Figure 8-2a represents the height of the fluid before mixing or generation of CGA's (h_{l0}). Figure 8-2b shows the initial height of the aphronized fluid in the graduated cylinder. The height of the fluid is recorded as (h_t). With time, the total height (h_t) of the solution will decrease. The base fluid will drain out of the foams and will accumulate at the bottom of the cylinder (Figure 8-2c). The height of the drained base fluid (h_i) as well as the total height (h_t) are recorded with time.

The velocity of the CGA in stagnant water, v_s , can be calculated by Equation (8-2).

$$v_a(t) = \left[\frac{(1 - \varepsilon)}{(1 - \varepsilon + \varepsilon / 0.707)} \right] \times v_s \quad 8-2$$

where ε is the gas holdup of the aphronic phase and $v_a(t)$ is the CGA rise velocity. This velocity can be assumed to be equal to the velocity of the interface shown in Figure 8-2c. The gas holdup can be determined by an expression depending on the heights of the system.

$$\varepsilon = \frac{(h_t - h_{lo})}{(h_t - h_i)} \tag{8-3}$$

where h_t is the total height of the solution, h_{lo} is the initial solution height and h_i is the height of the drained surfactant solution.

An experimental study was conducted to estimate the CGA bubble diameter using the drainage model concept (Section 4.4.1). Table 8-1 illustrates the input parameters used to estimate the CGA bubble diameter from Equation (8-1) for the various experimental runs. The viscosity of the fluid was estimated at the lowest shear rate that could be measured with the Brookfield viscometer (0.6 sec^{-1}). The lowest value was utilized because during creaming the fluid is in a stagnant situation and the only movement is due to gravity.

Table 8-1: Parameters used to solve Equation 8-1.

	Parameter			
	μ_w (Pa.s)	ρ_a (Kg/m ³)	ρ_w (Kg/m ³)	g (m/s ²)
No XG, diameter of shell neglected	0.001	1.184	1000	9.81
0.5 lb/bbl XG, viscosity at 0.6 sec ⁻¹ shear rate	0.2	1.184	1000	9.81
1 lb/bbl XG, viscosity at 0.6 sec ⁻¹ shear rate	1.4	1.184	1000	9.81

Figure 8-3 and Figure 8-4 show the predicted diameter for the solutions prepared by using 0.5 lb/bbl and 1 lb/bbl of Xanthan Gum (XG) base fluid respectively. Both figures also show the experimentally measured diameter of the CGA. The procedure for measuring CGA diameters can be found in Section 5.1.1. Figure

8-3 shows that the predicted values of the diameter of the CGAs are less than that of the ones that were measured by experiments. This was also the observation of

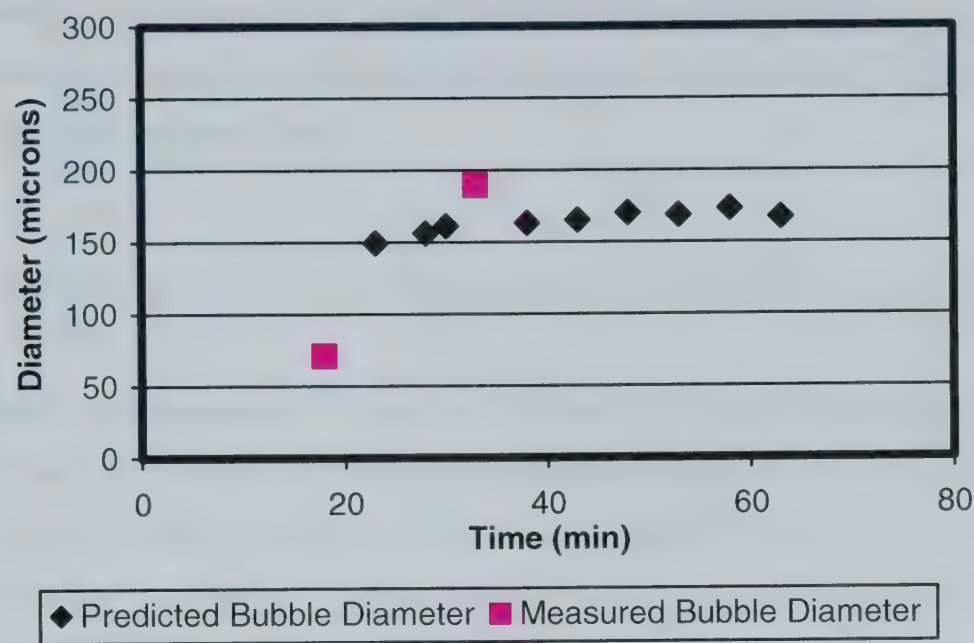


Figure 8-3: Comparison of predicted and measured CGA diameter with time for the drainage rate model with a base fluid concentration of 0.5 lb/bbl Xanthan Gum (XG).

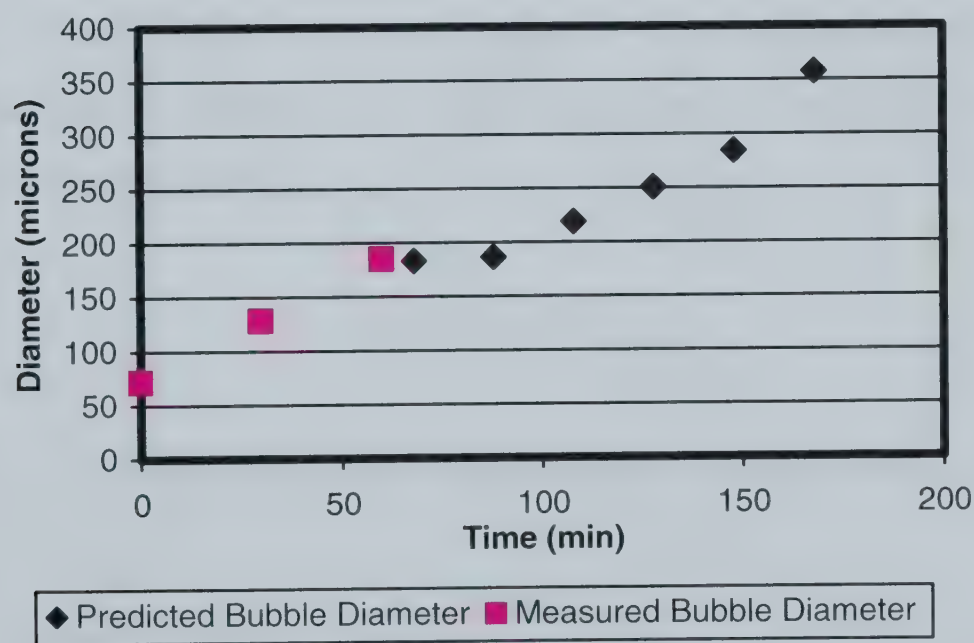


Figure 8-4: Comparison of predicted and measured CGA diameter with time for the drainage rate model with a base fluid concentration of 1 lb/bbl Xanthan Gum (XG).

Jauregi et al. (2000) who compared experimental results with various surfactant concentration, salt concentration, pH and stirring time. Figure 8-4 shows that the initial predicted values are close to the measured value at approximately the same time. Comparison of the experimental results with the model predictions show that the drainage model can supply a rough estimate of the CGA diameter over extended periods of time.

8.1.2 Bubble Breakup Model (Parthasarathy et al. (1991) and Jauregi et al. (2000))

The bubble breakup model is based on the theory that the diameter of a bubble can be determined from inertial forces and surface tension forces under turbulent conditions in a mixing apparatus. The critical Weber number is defined as the ratio of inertial and surface tension forces needed to break up a bubble and is given as follows:

$$W_{e_c} = \frac{\rho \overline{u^2} d_{\max}}{\sigma} \quad 8-4$$

where ρ is the density of the liquid phase, $\overline{u^2}$ is the squared mean velocity difference over the maximum bubble diameter, $d_{\max}$, and σ is the surface tension. $\overline{u^2}$ can further be defined by:

$$\overline{u^2} = C_I (E d_{\max})^{2/3} \quad 8-5$$

where C_I is a constant and E is the energy dissipation rate per unit mass.

$$E = P / \rho V \quad 8-6$$

where P is the power consumption and V is the liquid volume. Combining Equations (8-4), (8-5) and (8-6):

$$d_{\max} = C_2 \left(\frac{\sigma^{3/5}}{\left(\frac{P}{V_i} \right)^{2/5} \rho^{1/5}} \right) \quad 8-7$$

where C_2 is an empirical constant and V_i is the impeller swept volume which can further be defined by:

$$V_i = \pi D^2 W / 4 \quad 8-8$$

where D is the impeller diameter and W is the blade width.

The Sauter mean bubble diameter can then be determined by modifying Equation (8-7).

$$d_{32} = C_3 \left(\frac{\sigma^{3/5}}{\left(\frac{P}{V_i} \right)^{2/5} \rho^{1/5}} \right) \quad 8-9$$

Two conditions must be met for the use of the bubble breakup equation (Equation 8-8). Firstly, the Impeller Reynolds Number must be greater than 10^3 .

$$\text{Re} > 10^3 \quad 8-10$$

Secondly, the length scale of the primary eddies (L) must be greater than the diameter of the CGAs (d) which must be greater than the length scale of the energy dissipating eddies (η) of the viscous subrange.

$$L \gg d \gg \eta \quad 8-11$$

In order to meet the first condition the value of the Impeller Reynolds Number can be calculated through the following equation:

$$Re = \rho N_i D^2 / \mu \quad 8-12$$

Where ρ is the density of the liquid or continuous phase, N_i is the mixing speed, D is the impeller diameter, and μ is the viscosity of the liquid phase at the mixing speed.

In order to meet the second condition the values of L , d and η must be known. d is assumed to be the average CGA diameter. L can be approximated to the impeller blade width. The length scale of the energy dissipating eddies (η) can be estimated from the following equation:

$$\eta = (v^3/E)^{0.25} \quad 8-13$$

where v is the kinematic viscosity and E is defined as the energy dissipation rate per unit mass and is found by Equation (8-6). In this case, the liquid volume should be taken as the impeller swept volume (V_i) and can be calculated by Equation (8-8).

For the first condition of the bubble break up equation, the value of the Impeller Reynolds number for this system should be greater than 10^3 . By using the experimental values of 1000 kg/m^3 for density of the base fluid (ρ), 5000 rpm for the mixing speed (N_i), 0.041 m for the diameter of the impeller and 1 cp for the viscosity of the liquid phase (μ) we find that the Reynolds number greater than 10^3 . Therefore the first condition is satisfied. At the mixing speed used, the viscosity of the base fluid is expected to be very low since the fluid is shear thinning. The 1 cp value is an estimate based on the measured values of viscosity versus shear rate reported in Chapter 3.

For the second condition, L can be approximated as the impeller blade width. Therefore L is 0.013 m. Based on a power of 1000 W, a swept volume (V_i) of 0.000017 m^3 and an E of 58823, η becomes 0.000002. The measured average CGA diameter is 0.00006 m which is in between the value of L and η . Therefore the second condition is satisfied.

In order to solve for the Sauter mean diameter given in Equation (8-9), C_3 , the surface tension (σ), density (ρ), power (P) and impeller swept volume (V_i) must be known. Table 8-2 lists the values used in this study. The power values were determined using a power measuring device called a Kill-A-Watt. The density was assumed to be constant for each base fluid (1000 Kg/m^3) since it does not exhibit a significant change throughout the conditions of the study. The surface tension was measured using the Surface Tensiomat Model 21. As shown in Table 8-2, it is evident that the power consumption is drastically different for the various runs. This is due to the efficiency of the two mixers used in the study, the Brinkmann Homogenizer Model PT 45/80 and the Polytron PT 6100 Generator. The impeller swept volume ($1.7 \times 10^{-5} \text{ m}^3$) is assumed to be the same for every run as the impeller used remained constant.

Parthasarathy et al (1991) suggested plotting the group of terms in parenthesis in Equation (8-8) versus the experimentally determined values of d_{32} to find the constant C_3 . With this in mind, the experimental values for the diameter of the CGA bubble that were presented in Chapter 5 have been plotted against the values of the group of terms in the parenthesis of Equation (8-9). The result of this plot is shown in Figure 8-5. The figure illustrates the value of the constant C_3 as given by Parthasarathy et al. (1991) ($C_3 = 2$) as well as the best fit value of C_3 from the experimental data. Figure 8-5 shows that the data is fairly scattered. Since the best fit constant is very close to the value presented in the literature, a value of $C_3 = 2$ was selected for use to estimate d_{32} .

Table 8-2: Values used for calculation of Sauter mean bubble diameter using Equation (8-9).

XG Amount (lb/bbl)	Surfactant DDBS Amount (lb/bbl)	Speed (RPM)	Mixer used	σ (N/m)	P (W)
1	2	High	Homogenizer	0.0324	1050
3	1	High	Homogenizer	0.0351	1100
3	2	High	Homogenizer	0.0351	1100
3	2	Medium	Homogenizer	0.0351	850
3	2	Low	Homogenizer	0.0351	180
0.5	1	5000	Generator	0.0273	190
1	1	5000	Generator	0.0324	175
2	1	5000	Generator	0.0326	150
2	0.035	5000	Generator	0.0455	150
2	0.35	5000	Generator	0.0326	150
2	1	10000	Generator	0.0326	315
2	1	15000	Generator	0.0326	715

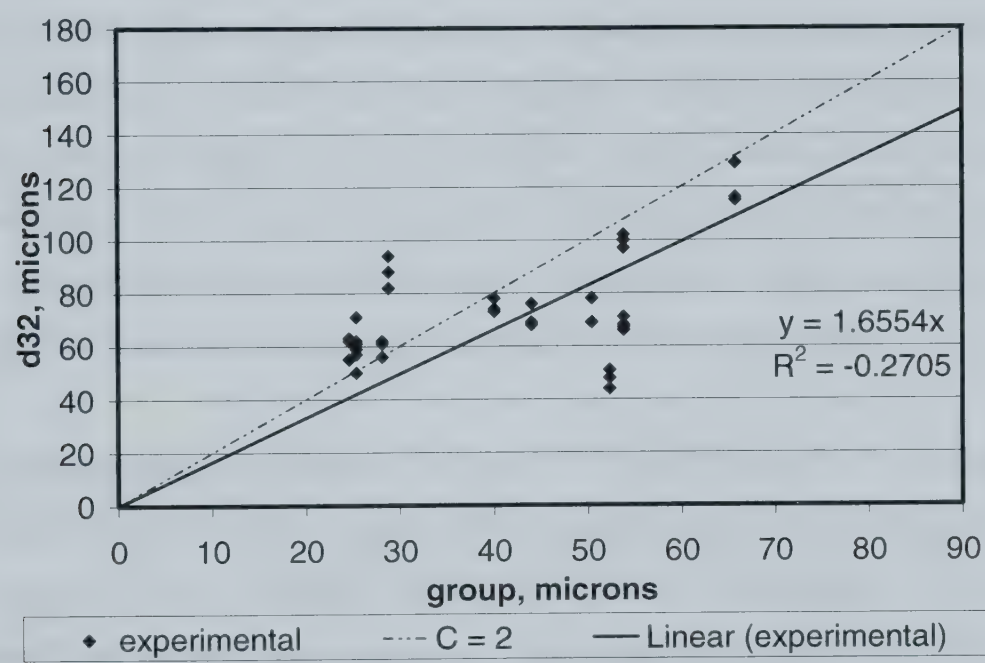


Figure 8-5: Experimental Sauter mean bubble plotted against the group

$$\sigma^{3/5} / \left(\frac{P}{V_i} \right)^{2/5} \rho^{1/5}$$

8.1.2.1 CGA Diameter with Pressure and Temperature

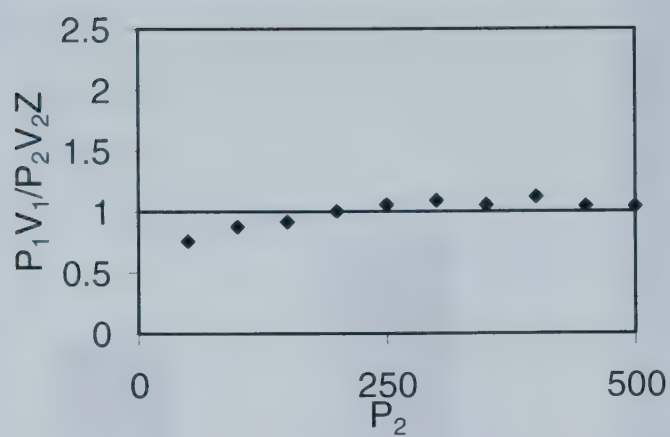
Although the previous two models presented can give an estimate of bubble size, neither of them are reliable predictors. Therefore, it was concluded that a new model should be developed based on the experimental findings of Chapter 5.

A microbubble (CGA) contains an air core. Therefore, when considering the change in an CGA diameter with pressure and temperature, the ideal gas law is a logical place to start. In Section 5.5, it is reported that with a change in polymer (XG) concentration of the base fluid, the change in CGA diameter varied with increasing pressure. Figure 8-6 and Figure 8-7 illustrate the deviation of the experimental data presented in Section 5.5 from the ideal gas law. In the figure, the horizontal line that crosses the y-axis at 1 represents the ideal case. Thus any deviation from 1 would indicate a deviation from the ideal gas law. From Figure 8-6 it is evident that as the pressure increases, the ratio of $P_1 V_1 / P_2 V_2$ increases and the deviation from the ideal gas law increases. As well, with higher polymer (XG) concentration, there is a greater deviation from the ideal gas law. Figure 8-7 also shows that with an increase in polymer (XG) concentration of the base fluid, the deviation from the base line increases. Therefore it was concluded that the ideal gas law is not the best predictor for the CGA fluid in question.

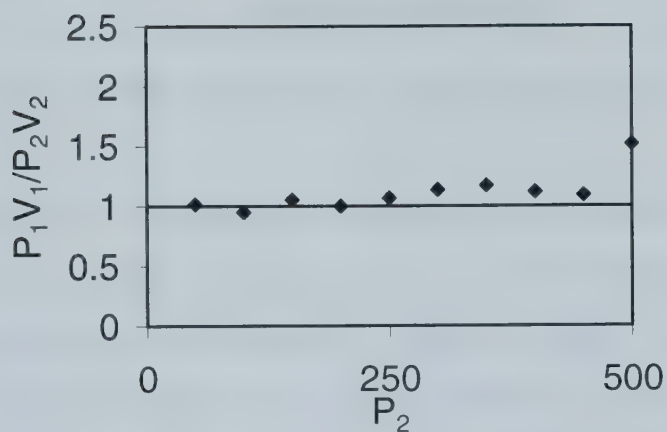
The experimental data presented in Section 5.5 and Section 5.6 for a change in CGA bubble diameter with pressure and temperature was then used to develop a new equation for the prediction of bubble diameter with pressure, temperature, and base fluid polymer concentration. The equation was developed via curve fitting techniques.

$$d = (-0.22C_p - 7.33)\ln(P) + (1.02 - 0.04C_p)\Delta T - 3.36C_p + 77.21 \quad 8-14$$

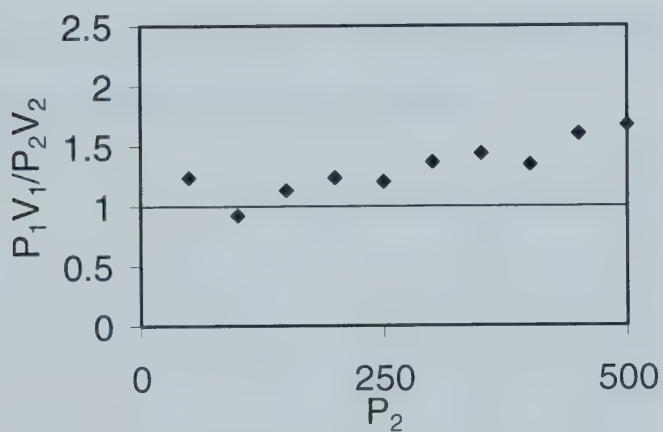
Here d is the diameter in microns, C_p is the concentration of polymer in lb/bbl, P is the pressure in psig, and ΔT is the temperature change between the mixing temperature and the reservoir temperature in °C.



a)



b)



c)

Figure 8-6: Comparison of experimental data to the ideal gas law for a CGA formulation of 1 lb/bbl surfactant (DDBS) and a) 1 lb/bbl polymer (XG), b) 2 lb/bbl polymer and c) 3 lb/bbl polymer.

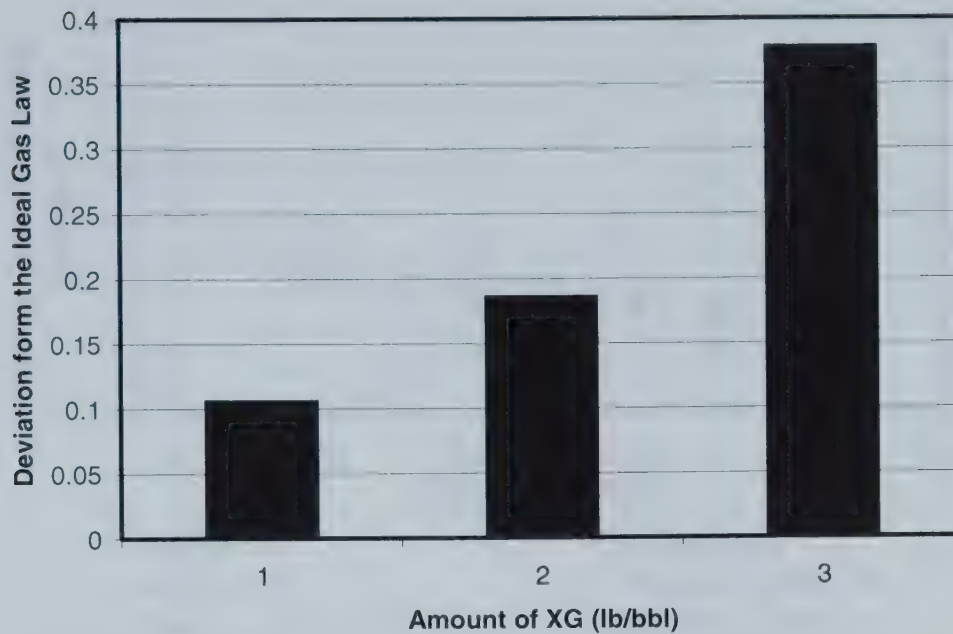


Figure 8-7: Deviation from the ideal gas law with concentration of XG

Figure 8-8 and Figure 8-9 compare the prediction of Equation (8-14) to the experimental data presented in Sections 5.5 and 5.6 for the change in CGA diameter with pressure and temperature. Figure 8-8 shows that the prediction remains quite accurate through the range of pressures presented. Figure 8-9 shows that the predictions does not follow the scatter in the experimental data over the range of temperatures presented. Figure 8-10 compares all of the experimental data to the predicted data. It demonstrates that the prediction mated the whole of the experimental data quite accurately.

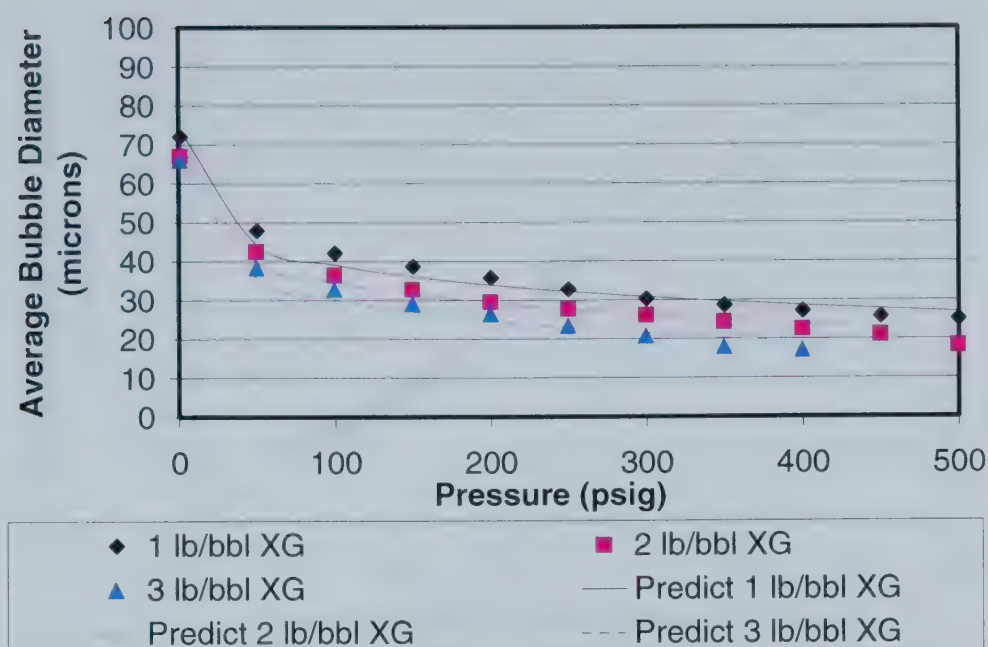


Figure 8-8: Comparison of predicted and experimental data for CGA bubble diameter with a change in pressure at varied polymer (XG) concentration

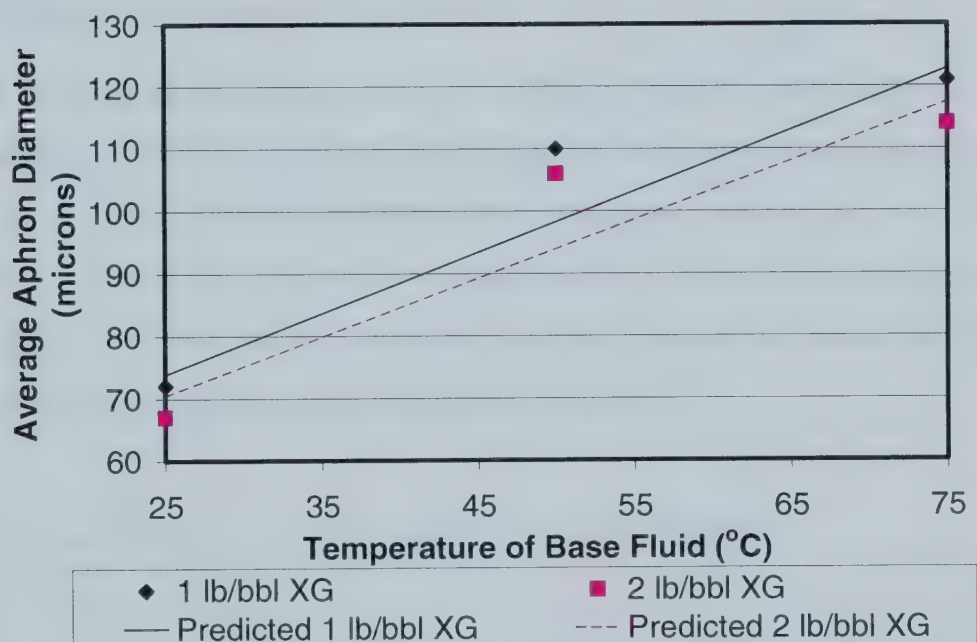


Figure 8-9: Comparison of predicted and experimental data for CGA diameter with a change in temperature at varied polymer (XG) concentrations

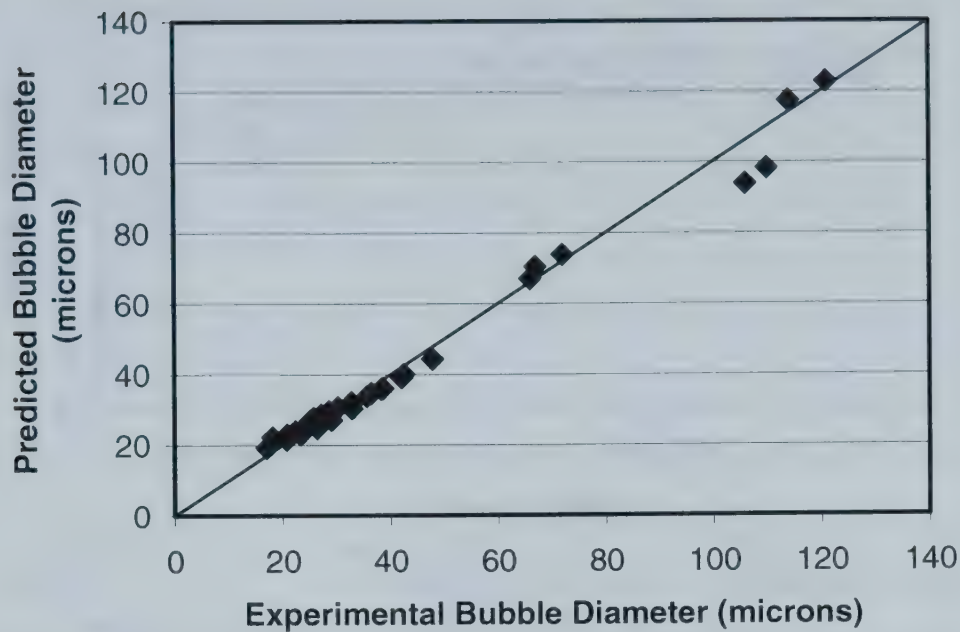


Figure 8-10: Comparison of predicted and experimental bubble diameter presented in Sections 5.5 and 5.6.

8.1.3 Equation of State for CGA Fluid

Change in bulk fluid volume with a change in pressure and temperature was measured using a PVT apparatus and the results were presented in Section 4.4.2. Equation (8-14) was developed from the experimental data using a curve fitting technique. Figure 8-11 shows the experimental data and the prediction using Equation (8-14). It predicts the density of the fluid at different pressures and temperatures for a polymer concentration of 2 lb/bbl.

$$\rho = (0.0019\Delta T + 0.3772)\ln(P) - 0.0163\Delta T + 6.2898 \quad 8-15$$

Here ρ is the density of the fluid in lb/gal, ΔT is the temperature change between the mixing temperature and the reservoir temperature in $^{\circ}\text{C}$ and P is the pressure of the system in psi. Figure 8-12 shows a comparison between the predicted density with Equation (8-15) and the experimentally measured density. It demonstrates that Equation (8-15) gives a reasonable prediction.

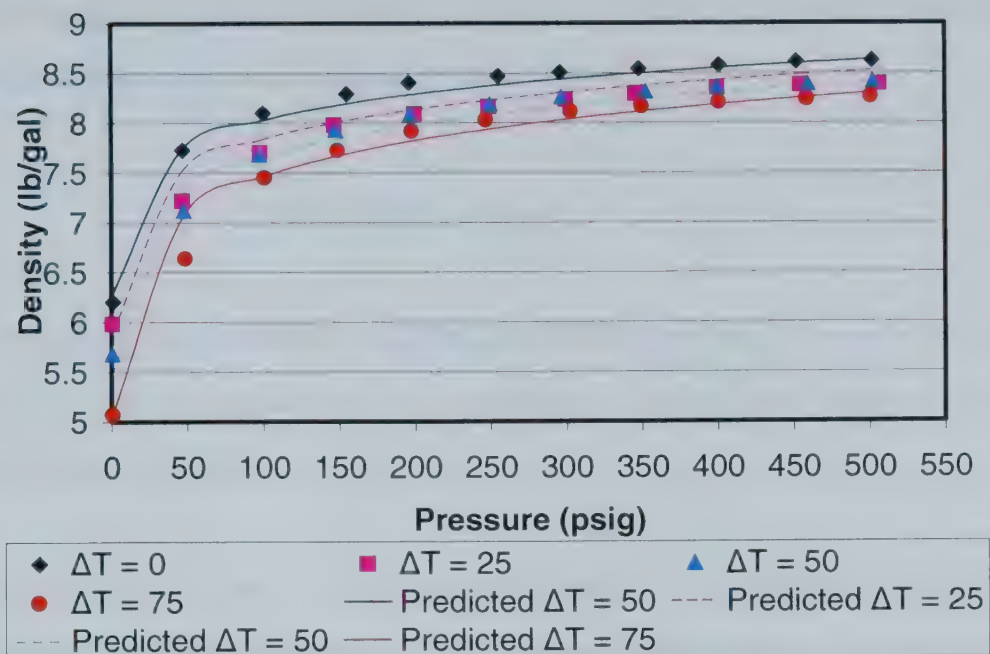


Figure 8-11: PVT data for 2 lb/bbl XG and 1 lb/bbl DDBS.

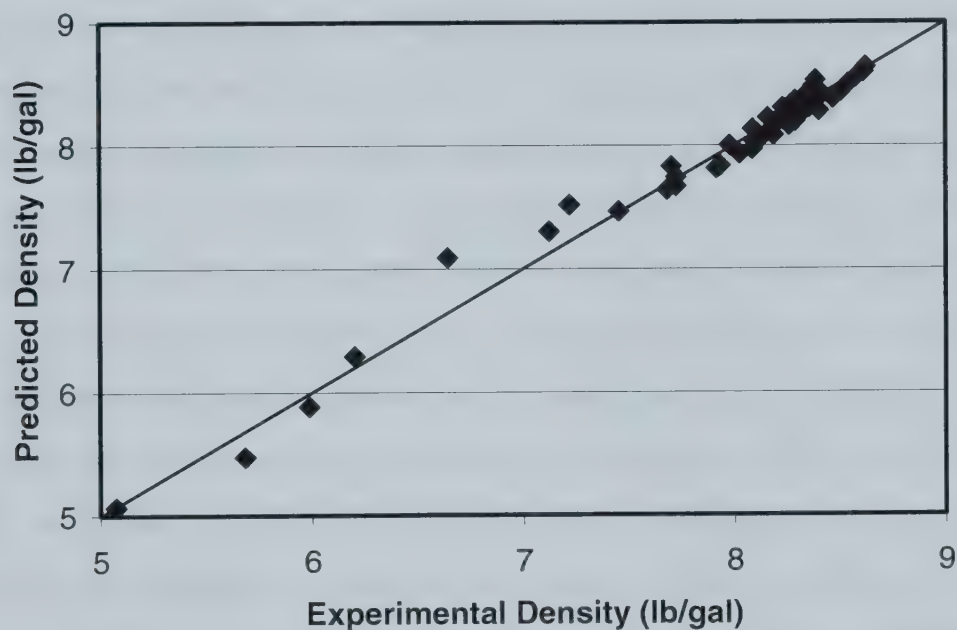


Figure 8-12: Predicted and experimental density from PVT Data

8.1.4 Pressure Prediction

With Equation (8-14) providing a reasonable prediction of CGA bubble size under various pressures and temperatures, the focus turns to examining the pressure

needed to invade a porous medium. In terms of capillary pressure, the equation for predicting the pressure needed for invasion is:

$$\Delta P = 2\delta(1/r_1 + 1/r_2) \quad 8-16$$

where P is the critical pressure required for CGA entry into a porous medium, δ is the surface tension, r_1 is the capillary radius and r_2 is the initial radius of the CGA (After Gardescu, 1930).

Data previously obtained by the micromodel experiments can be used to compare the results of applying Equation (8-15) to experimental data. The micromodels had a minimum pore throat diameter of 50 μm and 20 μm . The surface tension was measured using a Fisher Surface Tensiomat Model 21 and the estimated value obtained was 33 dyne/cm. With an average bubble size of 60 μm which was estimated experimentally in Chapter 5, Equation (8-16) predicts that the pressure needed to invade the micromodel would be 2.4 and 3.3 kPa for the 50 and 20 μm pore throat diameters, respectively. The measured pressures required for invasion for the two micromodels were 10 kPa and 30 kPa for the 50 and 20 μm pore throat diameters, respectively. Comparing these measured results to with values obtained by Equation (8-16) we find that Equation (8-16) underestimates the injection pressure somewhat. However, a comparison of the predicted results with the experimental results is difficult for the following reasons. Firstly Equation (8-16) describes one bubble entering one capillary and the micromodel experiment involves many bubbles entering many capillaries. Secondly, the pressure recorded in the experiment also includes the pressure needed to move the CGA fluid through the injection line to the micromodel. Another problem with utilizing Equation (8-16) for predictive purposes is that the value of surface tension is not always known. Therefore, in order to estimate a critical pressure required for CGA invasion in the field, it is more advantageous to use Equations (8-14) and (8-15). The following example shows how these equations can be used to predict invasion under field conditions.

8.2 FIELD EXAMPLE

Equations (8-14) and (8-15) can be utilized to determine the range of differential pressure that can be applied to the CGA fluid without significant invasion occurring. Typical conditions for a Lloydminster, Canada reservoir is listed in Table 8-3. Figure 8-13 shows the grain size distribution of a typical Lloydminster reservoir. From the figure it is evident that the range of grain size is from 100 to 250 μm . The distribution is also quite narrow with 50% of the grains having a size of 180 μm . Since the distribution is narrow, a median value for pore diameter was chosen for this study. A median pore throat diameter of 20 μm is estimated. The pore diameter will be used for this study as opposed to the pore throat diameter as it was observed in the experimental study of Chapter 7 that the CGA fluid invade the porous media and filled the pore bodies. Figure 8-14 shows a typical CGA diameter distribution. The range of diameters for the CGAs is also quite small so an average CGA bubble size will also be used for this study.

Utilizing the rule outlined by Abrams (1977) that the median particle size of the bridging additive should be equal to or slightly greater than 1/3 the median pore size of the formation, we can assume that the CGA threshold bubble size for bridging should be greater than 1/3 of 20 μm or approximately 7 μm . Table 8-4 lists the possible scenarios of temperature and polymer concentration and the resulting maximum pressure that can be applied to the drilling fluid based on the 1/3 rule. When comparing the maximum pressures listed in Table 8-4 to the average pressure of the Lloydminster reservoir listed in Table 8-3, all options are the viable ones as the maximum pressure of the options exceeds the reservoir pressure. Table 8-4 also lists densities calculated from Equation 8-15 at the maximum pressure. It should be noted however that Equation 8-15 was developed for 2 lb/bbl XG only and does not account for a change in density due to polymer concentration. Therefore, the predicted densities listed for the 1 lb/bbl case will most likely be an overestimate of the correct densities.

Table 8-3: Typical Lloydminster reservoir parameters

Temperature (°C)	20-25
Pressure (psi)	435
Permeability (D)	2-4
Porosity (%)	30
Viscosity (cP)	20000-50000

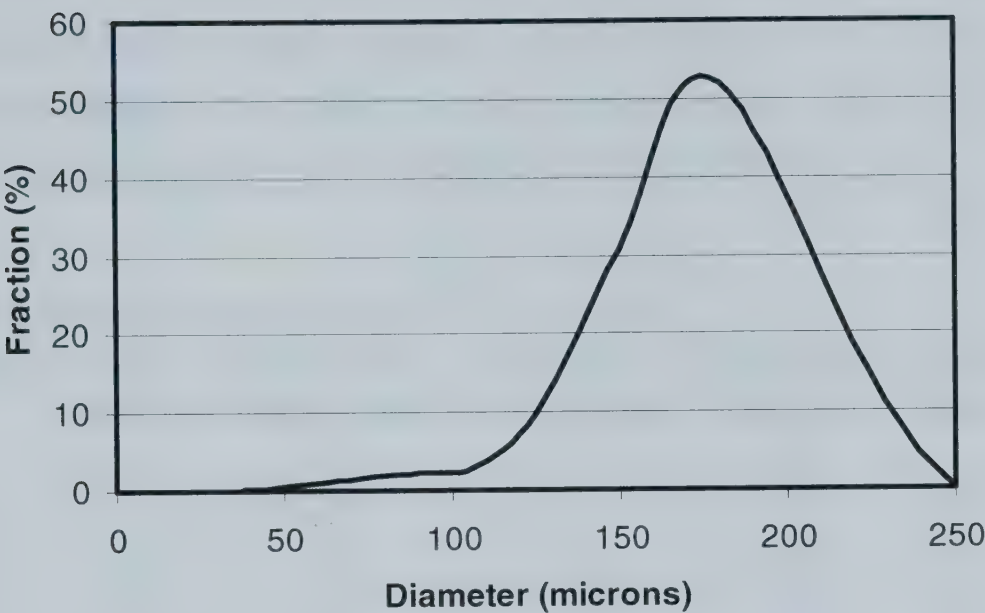


Figure 8-13: Grain size distribution for a typical Lloydminster reservoir

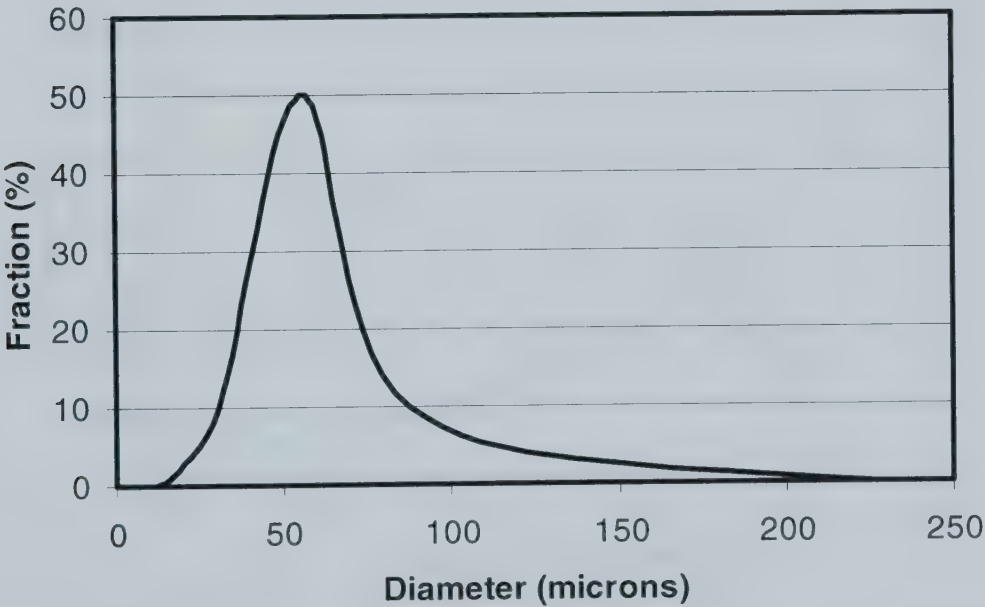


Figure 8-14: Typical CGA diameter distribution.

Figure 8-15 shows the threshold bubble size (7 μm) for a change in temperature and pressure when base fluid contains 2 lb/bbl of XG. It shows that as the differential temperature increases, the maximum pressure for which the bubble will not invade the formation also increases. The dependence of threshold bubble size on polymer concentration for a differential temperature of 0°C is shown in Figure 8-16. It shows that a decrease in polymer concentration increases the maximum pressure at which bridging can occur. Figure 8-17 summarizes the threshold pressure for various polymer concentrations while Figure 8-18 summarizes the density at various pressures and temperatures.

Table 8-4: Possible combinations for CGA injection

Option	Cp (lb/bbl)	Reservoir Temperature (°C)	Surface Temperature (°C)	Maximum Pressure (psi)	Density (lb/gal)
a	1	25	25	7000	9.63
b	1	20	25	3600	9.38
c	1	25	20	13000	9.87
d	2	25	25	3500	9.37
e	2	20	25	1900	9.15
f	2	25	20	6400	9.60

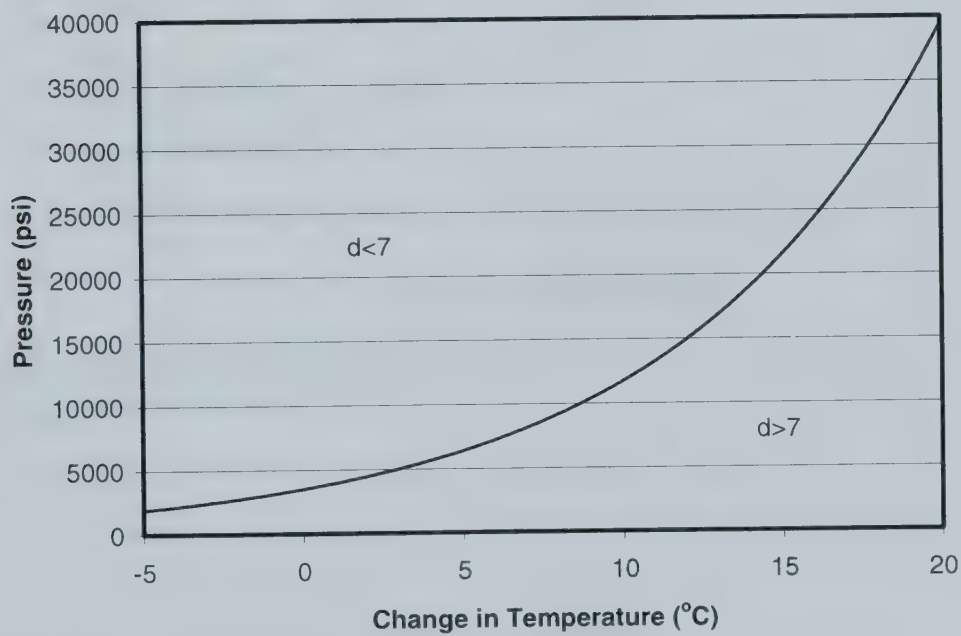


Figure 8-15: Bubble size threshold for 2 lb/bbl XG

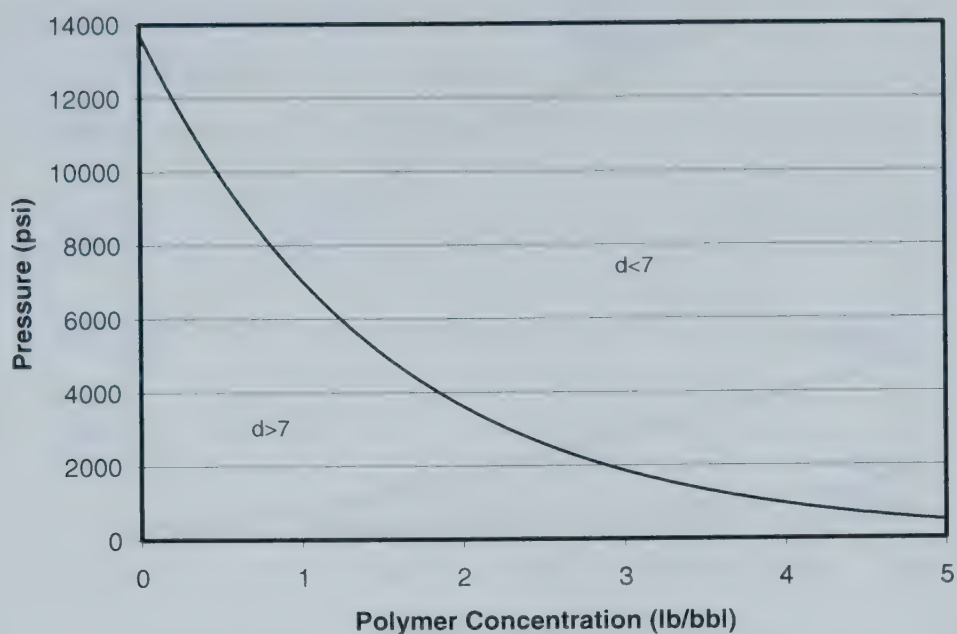


Figure 8-16: Bubble size threshold for a differential temperature of 0 °C

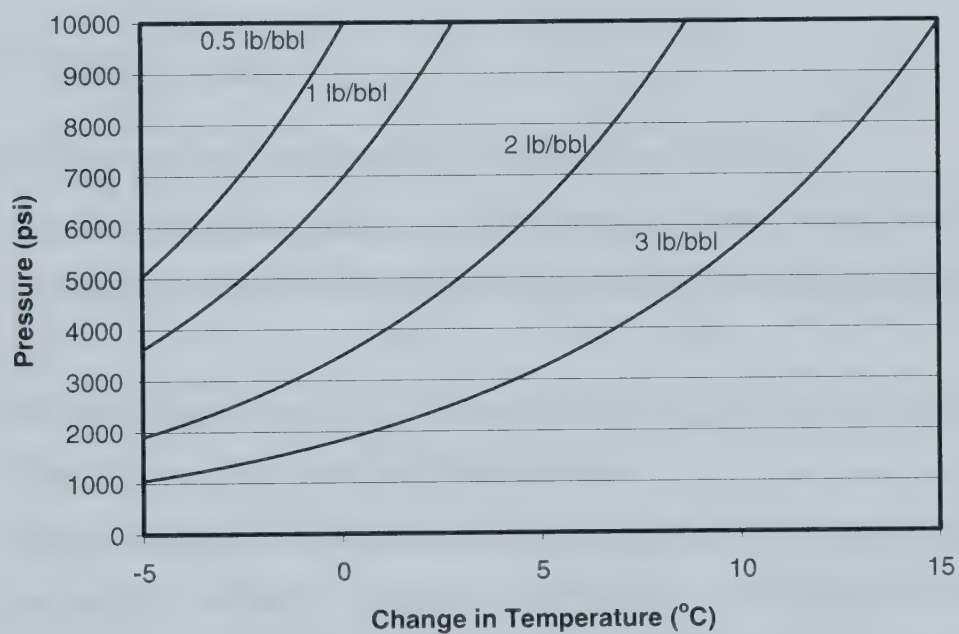


Figure 8-17: Pressure threshold for a various polymer concentrations at a bubble size of 7 μm .

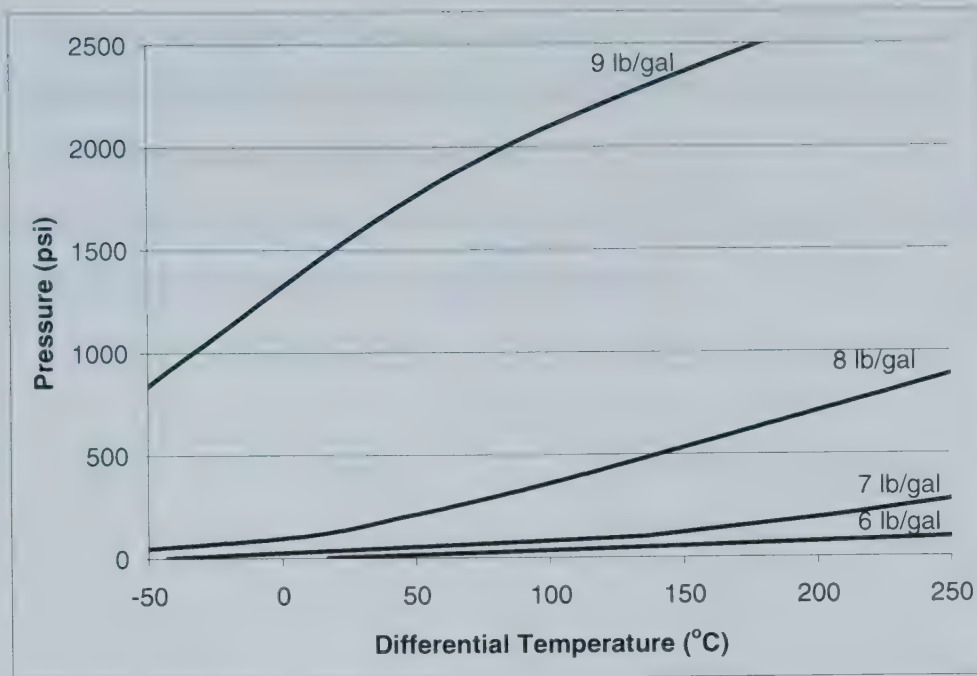


Figure 8-18: Density of CGA fluid at various pressures and temperatures

8.3 SUMMARY

As a result of this study, the following conclusions can be drawn:

- The drainage model (Amiri and Woodburn, 1990 and Jauregi et al., 2000) can supply a rough estimate of the CGA diameter over extended periods of time.
- The bubble break-up model (Parthasarathy et al., 1991 and Jauregi et al., 2000) is not a good predictor of bubble size.
- With an increase in XG base fluid, the change in CGA diameter tended to increase for increasing pressures. The ideal gas law could not represent this change. With an increase in XG base fluid, the deviation from the ideal gas law increases.
- There was a very close match between the experimental results and the predicted results when using the new correlation for bubble size presented here.
- There was a good match between the experimental results and the predicted results using the new correlation for density presented here.

- As the temperature difference between reservoir conditions and mixing condition increased, the maximum pressure at which the bubble will not invade the formation also increased.
- A decrease in polymer concentration increases the maximum pressure at which a bubble will not invade the formation.

9 CONCLUSIONS AND RECOMMENDATIONS

9.1 CONTRIBUTIONS AND LIMITATIONS

Overall, this study showed that the CGA fluid is successful at significantly reducing the transport of fluids through a porous medium. This is evident from the pressure rise observed in the sandpack and micromodel studies. The dependence of the blocking ability is firstly based on the pore size and CGA diameter and secondly dependent on the stability of the fluid to sustain the blockage over time. For the most part, CGA diameter is dependent on the equipment used to generate the CGA (evident from the change in diameter with mixing speed), the type of surfactant selected to generate the CGAs and the composition of the base fluid. The stability of the fluid is dependent on the composition of the CGA fluid.

It is evident that although CGAs do not follow the ideal gas law completely, the CGA diameter does shrink significantly with pressure. As well, CGAs become less stable as temperature increases. Therefore, CGAs are more likely to be suitable as a blocking agent in reservoirs with lower pressures and moderate temperatures. This study indicates that some CGAs do withstand pressure of up to 500 psi and temperature up to 75°C. Mature reservoirs would be good candidates for drilling with CGAs because of the depleted pressure. The field example in Chapter 9 showed that the CGA fluid could be able to block a typical Alberta reservoir.

9.2 CONCLUSIONS

The primary purpose of this study is to develop a better understanding of CGA based drilling fluid and the CGA bridging mechanism. This was accomplished through both experimental and modeling studies. For each task outlined in this work, major conclusions are drawn.

1. Generation Methods.

- CGAs were generated successfully in a laboratory setting with various concentrations of polymer and surfactant.
- Commercially available high speed mixers can be used to generate microbubbles. It was found that for the types of mixer utilized in this study, a baffled system did not enhance the CGA creation.

2. Bulk Characteristics

- The rheological behavior of the aphronized drilling fluids can be classified as yield pseudo plastic.
- Overall, the addition of the CGA to the base fluid increased the viscosity and the API filtration loss and decreased the density of the drilling fluid.
- As the polymer concentration increased the viscosity and density of the aphronized drilling fluid also increased while the volume of filtration loss decreased.
- An increase in the surfactant concentration decreased the filtration loss and increased the viscosity of the aphronized drilling fluid.
- Type of water did not influence the physical properties of the aphronized drilling fluids. Since the water quality showed little effect on all parameters, tap water can readily be used for preparing the base fluid.
- Aphronized drilling fluids generated by using cationic surfactants had lower filtration volumes as compared to fluids generated by using anionic surfactants. However, this may have been due to the presence of precipitates formed by chemical reaction between surfactant and polymer and not the CGA alone.
- Viscosity of the base fluid strongly influenced the stability of the fluid with time. Higher base fluid viscosity will lead to more stable microbubbles.
- For a fixed base fluid volume, more CGAs were generated at higher surfactant concentrations.

- As pressure increased and temperature decreased, the density of the fluid increased.
- Temperature increased the drainage rate of the CGA fluid and in turn decreased the stability of the fluid.
- Larger CGAs were created when the fluid was mixed at higher mixing (shear) rates. Higher shear rates also increased the viscosity while reducing the density of the aphronized drilling fluid. Increasing shear rate, however, did not cause any significant change on the filtration loss.
- CGA sizes increased as the mixing time increased from 10 seconds to 20 sec. However, bubble sizes did not change significantly between 20 and 30 seconds, indicating that there might be an optimum mixing time period to obtain maximum bubble size.
- CGA sizes generated by using cationic surfactants were larger than the ones generated by using anionic surfactants.
- Initial average CGA diameter was similar for all polymer (XG) concentrations. As polymer concentration increased, however, the bubble growth rate with time (i.e. stability) decreased.
- Increasing the polymer (XG) concentration above 2lb/bbl did not have any significant effect on retarding the bubble growth rate.
- An increase in surfactant concentration decreased the initial bubble size when the surfactant concentration is less than or near to the critical micelle concentration (CMC).
- Increasing the surfactant concentration decreased the bubble growth rate with time (i.e. more stable micro-bubbles).
- The bubble size decreased at a faster rate with increasing pressure at higher polymer concentrations.
- The bubble size decreased at a slower rate with increasing pressure at higher surfactant concentrations.
- Bubbles were unstable (i.e. bubbles are larger than their original size) when they are exposed to de-pressurization process following the pressurization.

- Increasing the temperature of the base fluid, increased the diameter of the CGA at surfactant concentrations higher than critical micelle concentration (CMC). The temperature effect on the bubble size is not significant at surfactant concentrations below CMC.
- Temperature effect on the bubble size decreased as the polymer concentration increased.
- Between 25°C and the 50°C, increase in bubble size was more drastic than from 50°C to 75°C, indicating that the CGAs were more sensitive to temperature change at lower temperatures.

3. Mechanism of CGA Bridging

a) Micromodel Study

- A stable CGA fluid was created and injected into the micromodel.
- The porous media was blocked by the stable CGA fluid as indicated by the pressure rise. Therefore, when drilling with aphronized fluid, aphrons will mitigate the fluid invasion into the rock and hence, will reduce formation damage.
- An CGA of 60 μm diameter will invade a porous medium saturated with water at a minimum pore diameter of 50 μm at around 10 kPa.
- An CGA of 60 μm diameter will invade a porous medium saturated with water at a minimum pore diameter of 20 μm at pressures greater than 30 kPa.
- The pressure increase with 50 mD was much slower than that for 200 mD for a fixed flow, indicating less stable CGA fluid in lower permeable situations.
- The pressure drop across the micromodel increased as the viscosity of the saturating fluid increased.
- Pressure drop increased at a faster rate as the base fluid viscosity increased indicating that a more viscous base fluid increased the stability of the CGA fluid.
- Long term stability of the CGA fluid was not achieved with a polymer

concentration of less than 0.1 lb/bbl.

- Pressure drop increased at a faster rate at lower surfactant concentrations. As surfactant concentration decreased, the amount of CGA's in the system decreased and viscous polymer injection increased per pore volume.
- With the exception of one case, the CGA fluid effectively displaced the crude oil from the water wet micromodel.
- For the conditions in these experiments, the optimum concentrations for the most effective CGA blocking is a polymer concentration greater than 0.1 lb/bbl and less than 3 lb/bbl and a surfactant concentration of 1 lb/bbl or greater.

b) Coreflow Study

- Higher pressure drop through porous media was observed when flowing CGA fluids formulated by using both polymer and surfactant (as compared to the flow of fluids formulated with only polymer and only surfactant). Higher resistance to CGA fluid invasion in this case indicated that both polymer and surfactant are needed for a stable CGA fluid.
- In most cases, the maximum pressure (i.e. pressure drop through porous media) required for injection of CGA fluid through porous media saturated with brine was similar to that of the case when water was used as saturation fluid.
- The maximum pressure required for injection of CGA fluid through porous media saturated with mineral oil was higher than that of the case when water was used as saturation fluid. This might be due to the fact that mineral oil has much higher viscosity than that of water.
- The maximum pressure required for injection of CGA fluid through porous media saturated with crude oil was lower than that of required for CGA fluid injection when water was used as saturation fluid. After injecting 6 PV of CGA fluid, the pressure drop across the sandpack is 18% less in the former case (i.e., crude oil is saturating fluid) than in the latter case (i.e., water is saturating fluid). This may be due to the instability of

CGA's in the presence of crude oil.

- Lower permeable sand packs result in a greater pressure rise and greater blocking ability.
- Wettability of the porous media has significant effect on the blocking ability of CGA's. CGA's block more efficiently in water-wet situations.
- CT images of the linear sandpack indicate the CGA fluid was present in the sandpack after more than 60 PV of water re-injection. The images also indicate that there was gravity separation between water and the CGA fluid.
- When comparing the pressure drop in the sandpack with water injection before and after CGA injection, the pressure after CGA injection was more than 200 times more than the pressure before CGA injection, indicating the CGA fluid was present in the sandpack after water injection.
- The linear sandpack test validates the data obtained in the radial sandpack tests.

4. Prediction Method for CGA Size, Stability and Blocking Ability.

- The drainage model (Amiri and Woodburn, 1990 and Jauregi et al., 2000) can supply a rough estimate of the CGA diameter over extended periods of time.
- The bubble break-up model (Parthasarathy et al., 1991 and Jauregi et al., 2000) is not a good predictor of bubble size.
- With a change in XG base fluid, the change in CGA diameter tended to increase for increasing pressures. The ideal gas law could not represent this change. With an increase in XG base fluid, the deviation from the ideal gas law increases.
- There was a very close match between the experimental results and the predicted results when using the new correlation for bubble size presented here.
- There was a good match between the experimental results and the predicted results using the new correlation for density presented here.

- As the temperature difference between mixing condition and reservoir conditions increased, the maximum pressure at which the bubble will not invade the formation also increased.
- A decrease in polymer concentration increases the maximum pressure at which a bubble will not invade the formation.

9.3 RECOMMENDATIONS

Although work has been done to determine what type of reservoir can be drilled with CGA fluid through the determination of blocking ability with CGA size and pore diameter, it is recommended that more testing be conducted to determine the effect of wettability on the blocking of the porous medium. Tests could include the use of the injection of CGA fluid into actual reservoir cores of various wettabilities (water-wet, oil-wet, mixed-wet) to determine the pressure rise and thus the blocking ability. As well, injection into a porous medium with elevated temperatures will give insight into the effect of blocking under elevated temperatures. Conducting these experiments will help to determine what type of reservoirs can be drilled with CGA fluid. An attempt should also be made to vary the diameter of the CGA fluid during the creation of the CGA.

A more detailed study should also be conducted on the effect of crude oil on the CGA fluid. Since crude oils from around the world have a variety of different components (ie., asphaltenes, resins, etc.), a study into the effect of the components will help determine the stability of the CGA fluid.

The sandpack study showed that formation damage of the sandpack was high and the CGA fluid was not easily removed from the pack. However, it would be of interest to understand the magnitude of formation damage with various differential pressures.

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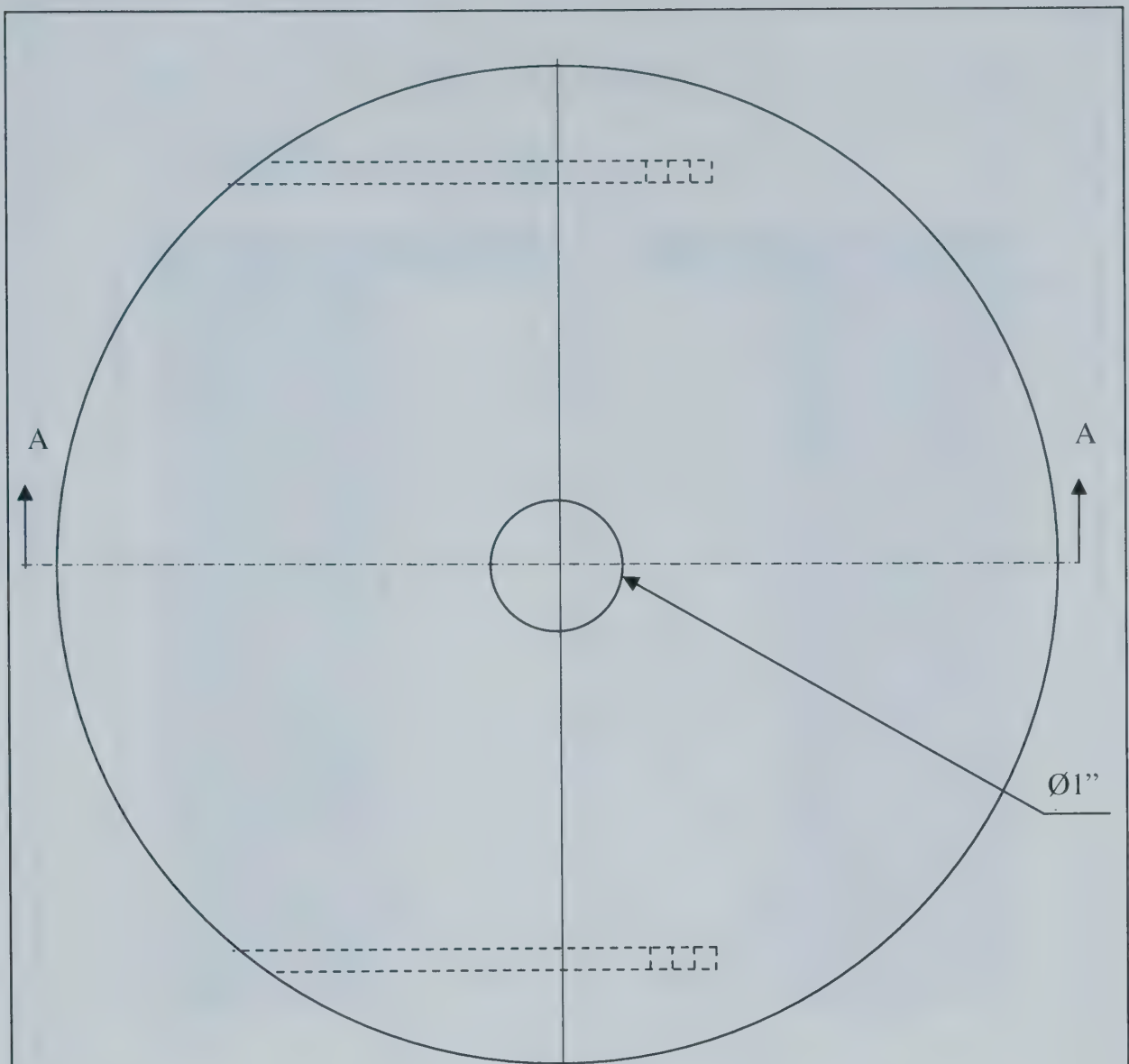
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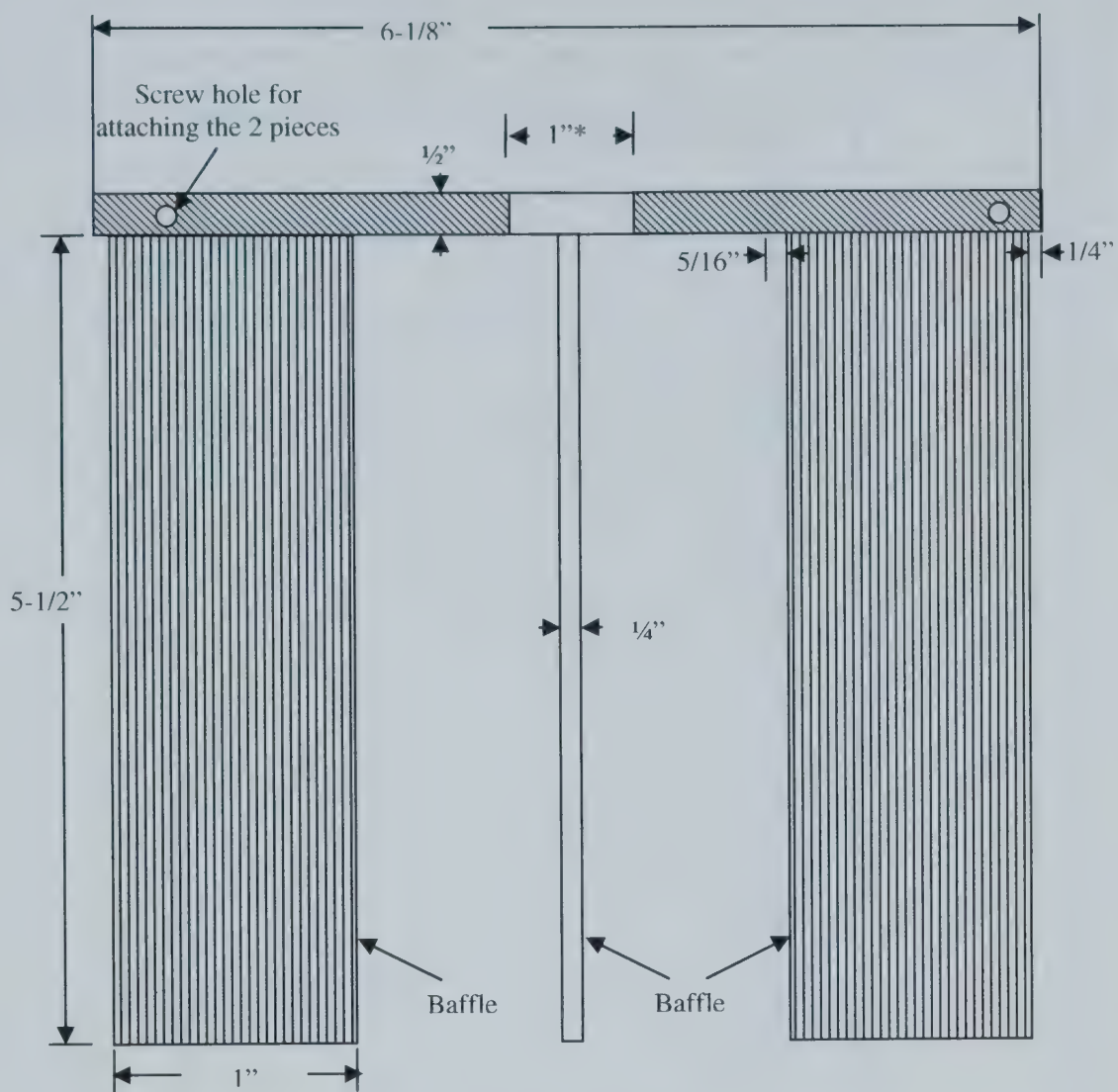
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APPENDIX A - DETAILED DRAWINGS OF THE BAFFLE SYSTEM



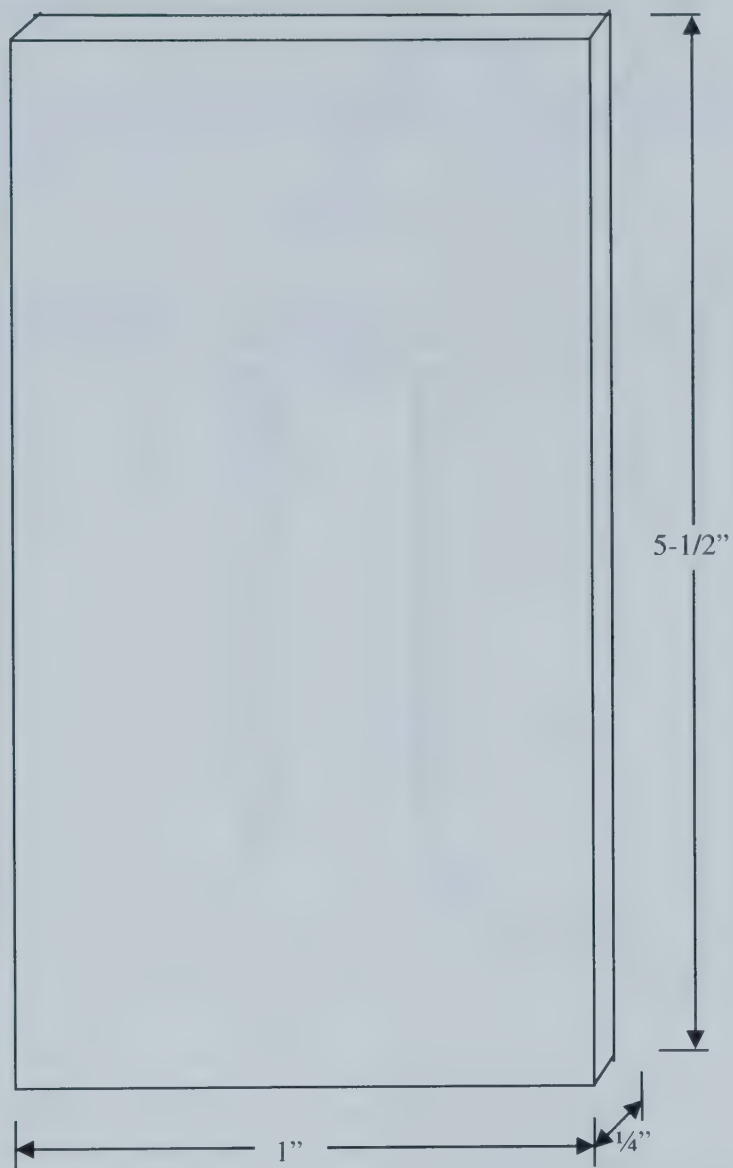
Top View
2 pieces

			School of Mining and Petroleum University of Alberta
Notes *Diameter to fit shaft -All dimensions dependant on prefabricated casing			
Drawn	08/04	NB	Baffled Mixing System - Top View
Modified	09/04	NB	
Approved			



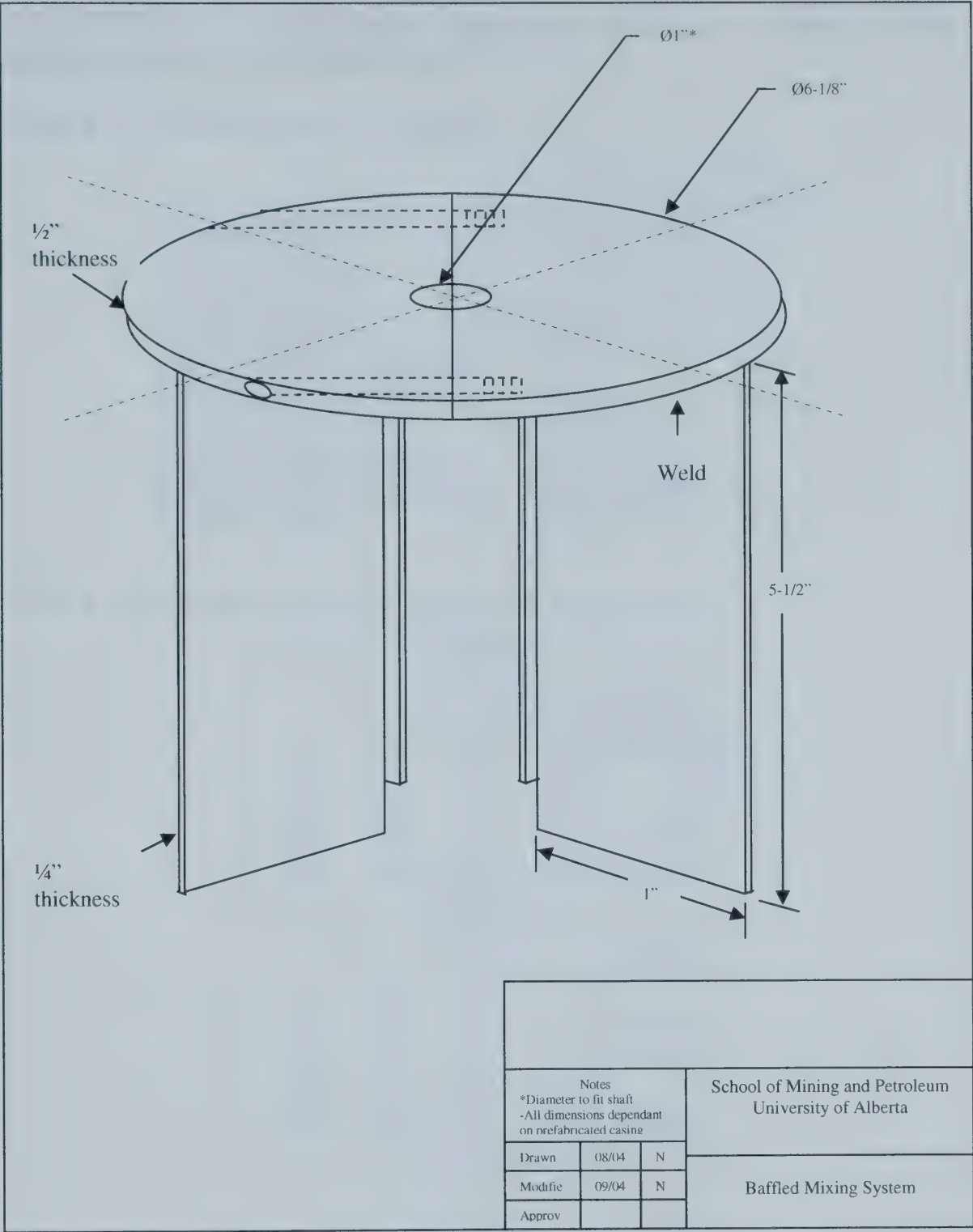
Section AA
Side View

			School of Mining and Petroleum University of Alberta
Notes *Diameter to fit shaft All dimensions dependant on prefabricated casing			
Drawn	08/04	NB	Baffled Mixing System - Section AA - Side View
Modified	09/04	NB	
Approved			



Baffle x 4

Notes All dimensions dependant on prefabricated casing			School of Mining and Petroleum University of Alberta	
Drawn	08/04	N		
Modified			Baffled Mixing System - Baffle x 4	
Approved				



APPENDIX B – COMPLETE RESULTS OF THE BUBBLE SIZE MEASUREMENT EXPERIMENTS

Table B - 1: Average initial CGA diameter.

	Ave			Ave for batch
	1	2	3	
XG1lb, DDBS2lb	55	62	63	60
XG3lb, DDBS2lb	61	62	57	60
XG5lb, DDBS2lb	60	59	56	58
XG3lb, DDBS1lb	61	62	57	60
XG3lb, DDBS2lb speed med	61	62	56	60
XG3lb, DDBS2lb speed low	51	48	44	48
XG3lb, DDBS2lb 20 sec	76	64	75	72
XG3lb, DDBS2lb 30 sec	72	71	71	71
XG3lb, DDBS2lb tap water	59	71	50	60
XG3lb, HTAB2lb	95	83	89	89

Table B - 2: Change in average diameter with time and rpm.

5000 rpm				
	Ave			Ave for batch
	1	2	3	
0	71	68	67	68.66667
30	89	100	96	95
60	111	112	107	110
120	142	138	144	141.3333
180	162	164	159	161.6667
10000 rpm				
	Ave			Ave for batch
	1	2	4	
0	78	74	73	75
30	130	122	136	129.3333
60	140	155	148	147.6667
120	199	214	211	208
180	221	233	237	230.3333
15000 rpm				
	Ave			Ave for batch
	1	2	3	
0	88	82	94	88
30	152	131	157	146.6667
60	177	158	170	168.3333
120	195		206	200.5
180	225		220	222.5

Table B - 3: Change in average diameter with time and XG concentration, 1 lb/bbl DDBS.

0.5 lb/bbl				
	Ave			Ave for batch
	2	3	5	
	0	69	76	68
30	190	219	159	189.3333
1 lb/bbl				
	Ave			Ave for batch
	1	2	4	
	0	69	69	78
30	128	121	136	128.3333
60	180	181	194	185
2 lb/bbl				
	Ave			Ave for batch
	1	2	3	
	0	66	66	68
30	99	94	104	99
60	137	120	157	138
120	174	164	172	170
180	189	199	185	191
3 lb/bbl				
	Ave			Ave for batch
	1	2	3	
	0	70	65	63
30	98	101	103	100.6667
60	113	129	120	120.6667
120	140	155	150	148.3333
180	152	179	171	167.3333
240	189	203	190	194

Table B - 4: Change in sauter mean diameter and average diameter with time and DDBS concentration, 2 lb/bbl XG.

0.035 lb/bbl				
	Ave			Ave for batch
	1	2	3	
0	116	115	129	119.9851
30	186	196	203	195.1043
60	221	203	243	222.2958
120	348	384	329	353.6973
180	382	395	410	395.5585
0.35 lb/bbl				
	Ave			Ave for batch
	1	2	3	
0	102	100	97	99.86825
30	162	176	160	166.1267
60	211	220	203	211.2462
120	287	274	281	280.4145
180	300	314	295	303.1709

Table B - 5: Change in sauter mean diameter and average diameter with time and temperature.

2 lb/bbl XG, 1lb/bbl DDBS				
	Ave			Ave for batch
	1	2	3	
25 C	66	66	68	66.66667
50 C	108	97	113	106
75 C	115	113	115	114.3333
1 lb/bbl XG, 1lb/bbl DDBS				
	Ave			Ave for batch
	1	2	3	
25 C	69	69	78	72
50 C	111	111	109	110.3333
75 C	123	124	115	120.6667
1 lb/bbl XG, 0.035 lb/bbl DDBS				
	Ave			Ave for batch
	1	2	3	
25 C	116	115	129	119.9851
50 C	120	105	102	109
75 C	110	105	121	112

APPENDIX C – IMAGES TAKEN DURING THE VISUALIZATION STUDY

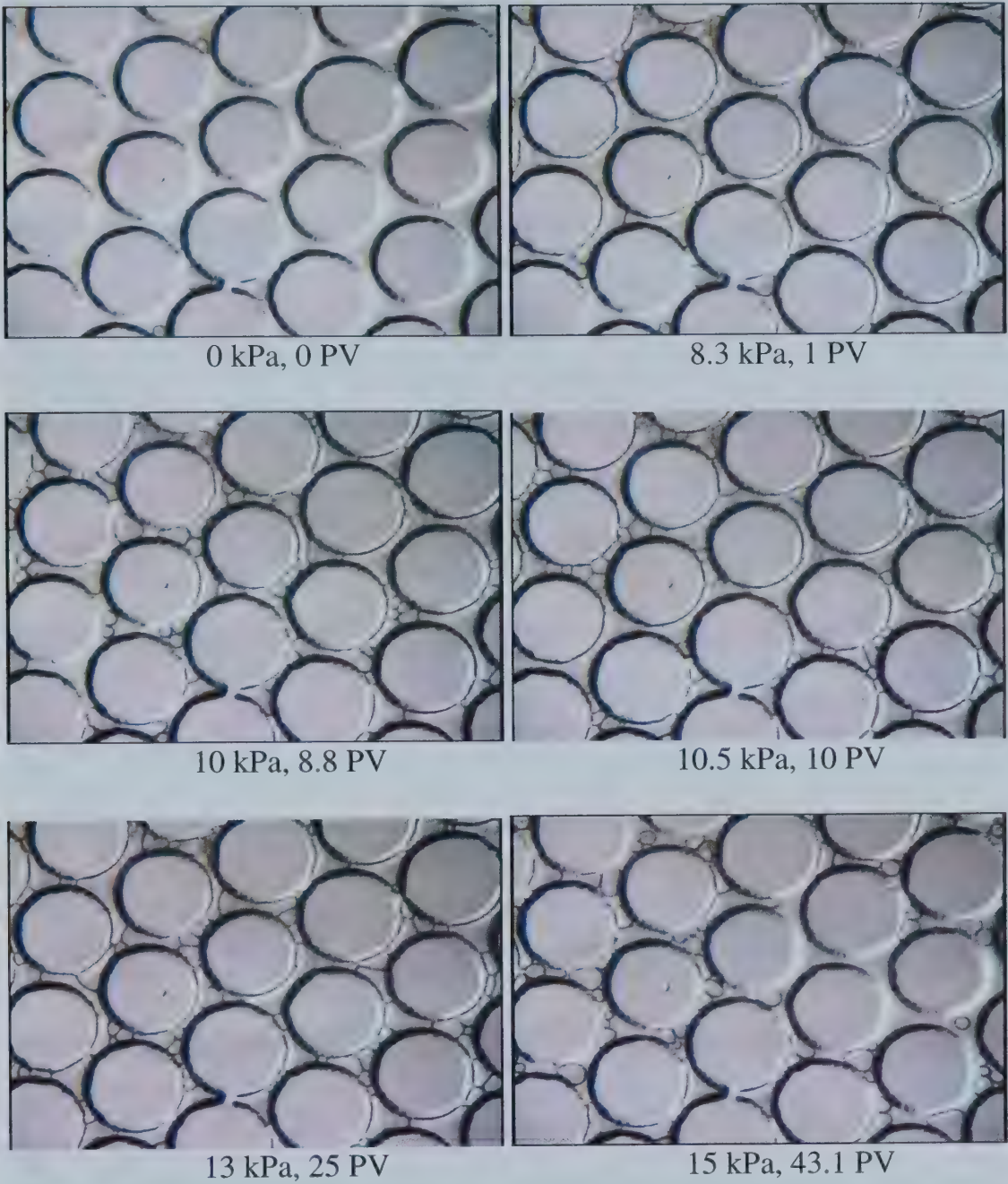
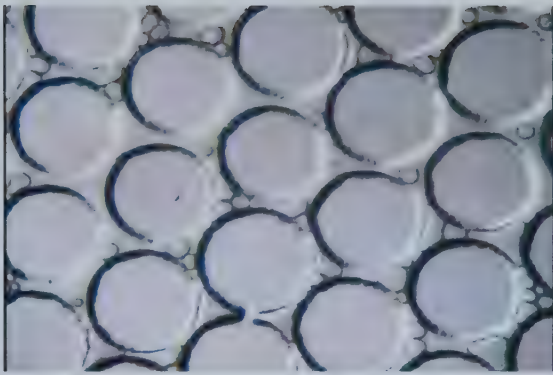
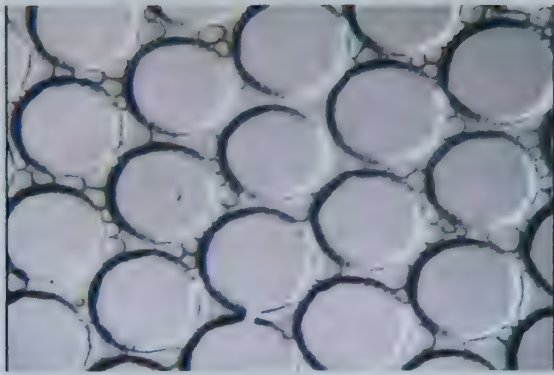


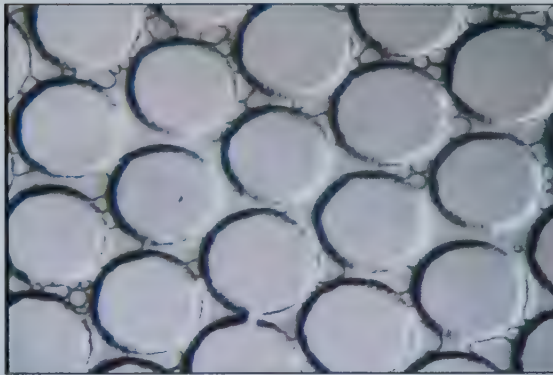
Figure C-1: Images of afoam flow through the microcell for W-P1-S2-R1-M1. Images taken at 1.6 x magnification.



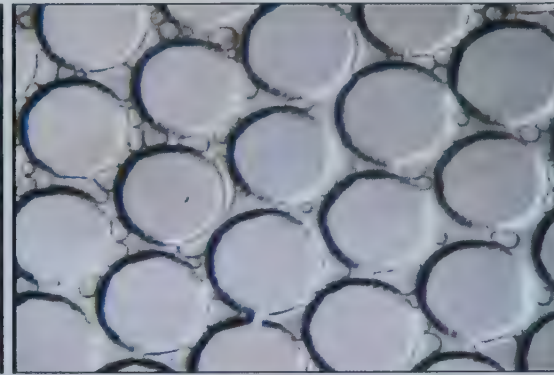
15.6 kPa, 50 PV



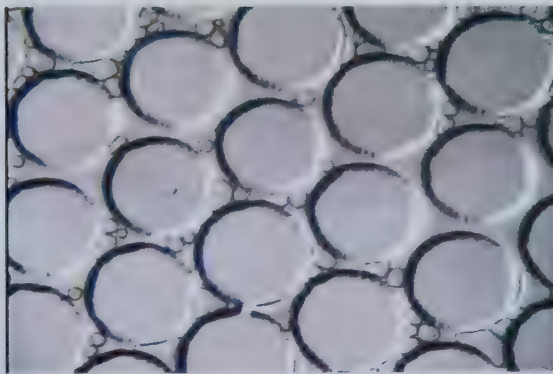
19 kPa, 100PV



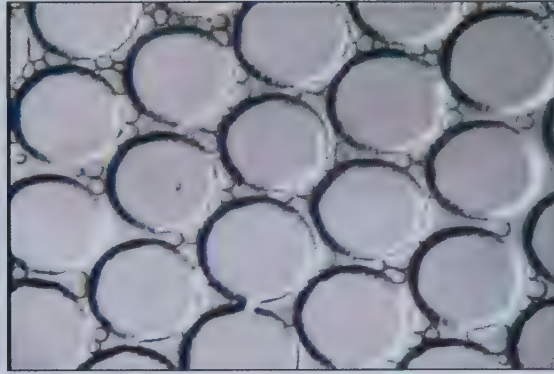
20 kPa, 113.7 PV



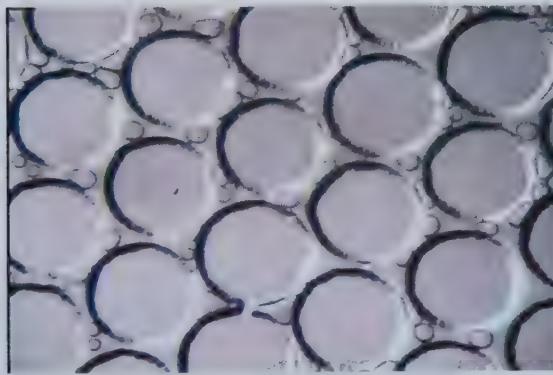
25 kPa, 185.3 PV



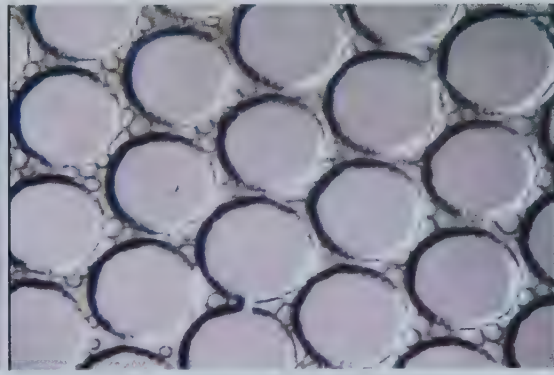
26.2 kPa, 200 PV



30 kPa, 250 PV

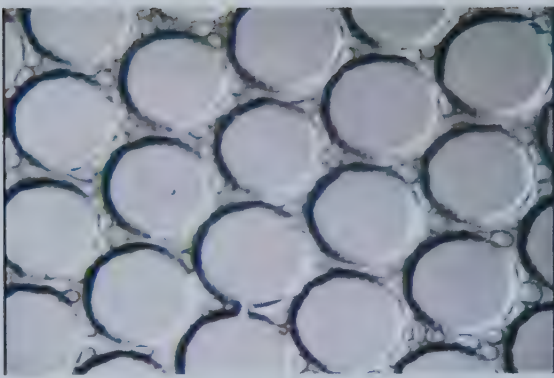


43.8 kPa, 400 PV

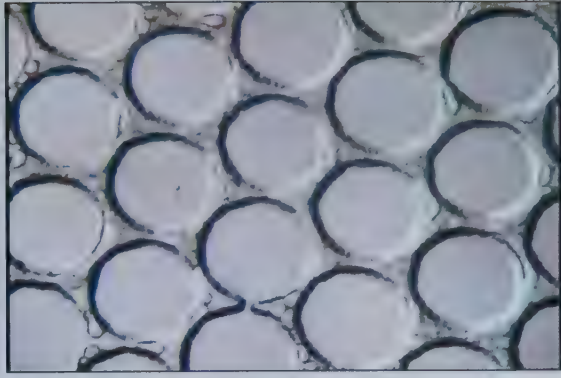


69.4 kPa, 600 PV

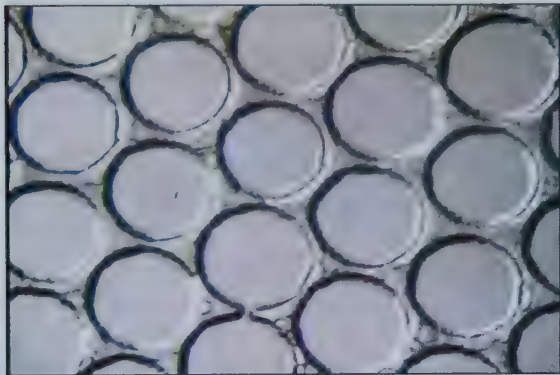
Figure C-1: Cont.



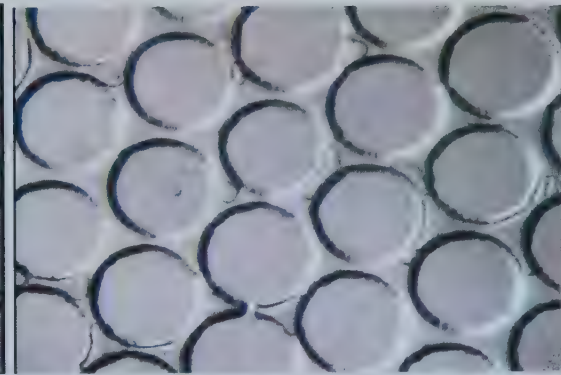
79.7 kPa, 800 PV



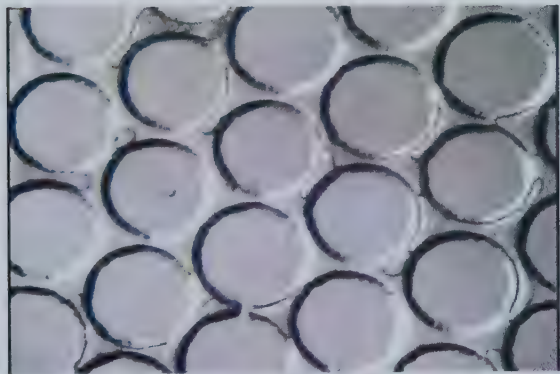
103.4 kPa, 965.7



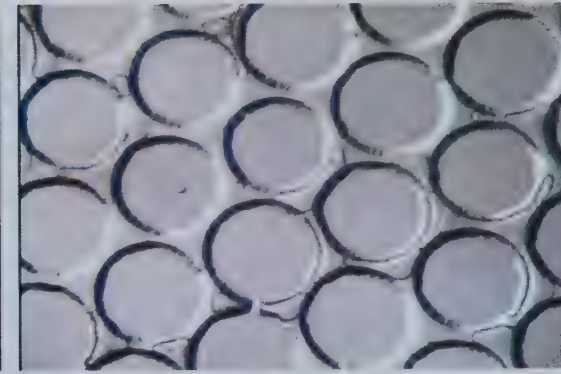
147.6 kPa, 1001 PV



43 kPa, 1200 PV



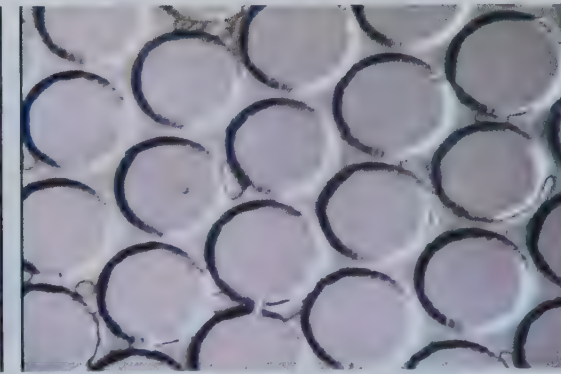
40 kPa, 1400 PV



38 kPa, 1600 PV

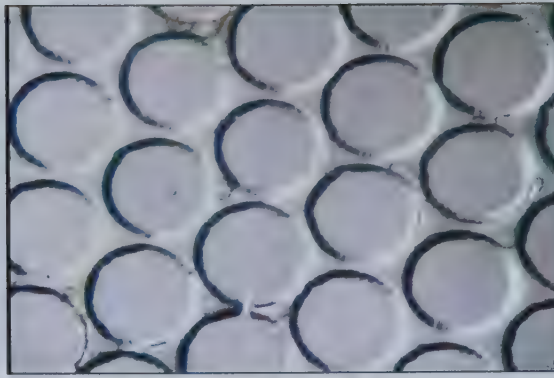


36 kPa, 1800 PV



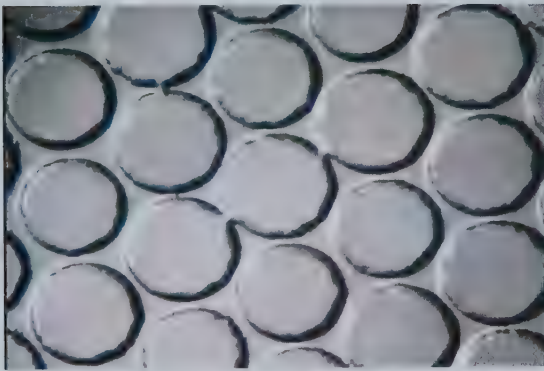
35 kPa, 2000 PV

Figure C-1: Cont.

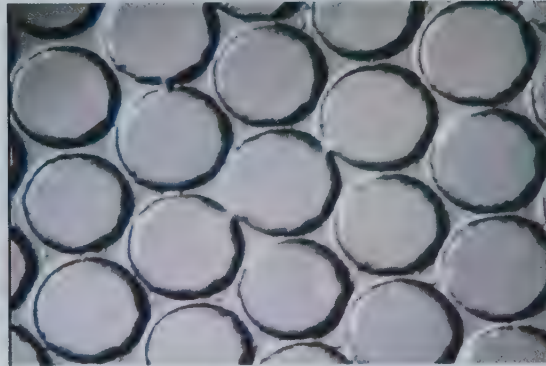


34.7 kPa, 2072.5

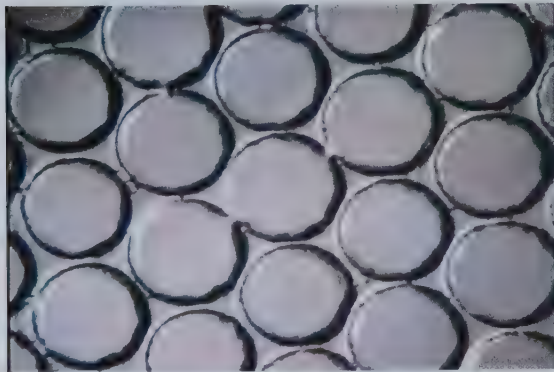
Figure C-1: Cont.



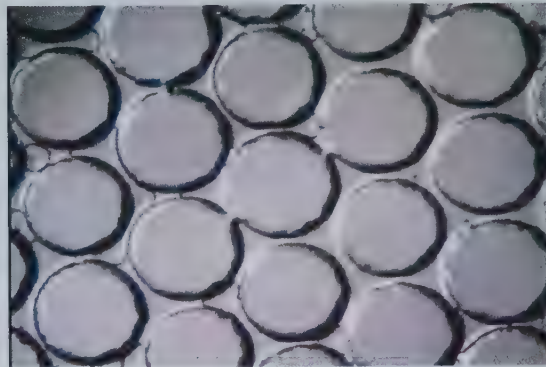
Initial



3.17 kPa, 1 PV



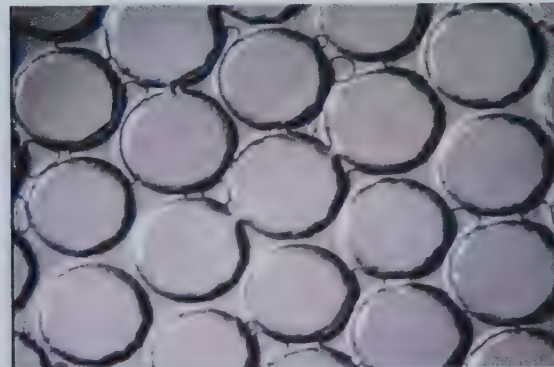
4.8 kPa, 10 PV



5 kPa, 16.2 PV



5.2 kPa, 25 PV



6.4 kPa, 50 PV

Figure C-2: Images of apheron flow through the microcell for W-P0.1-S2-R0.5-M1. Images taken at 1.6 x magnification.

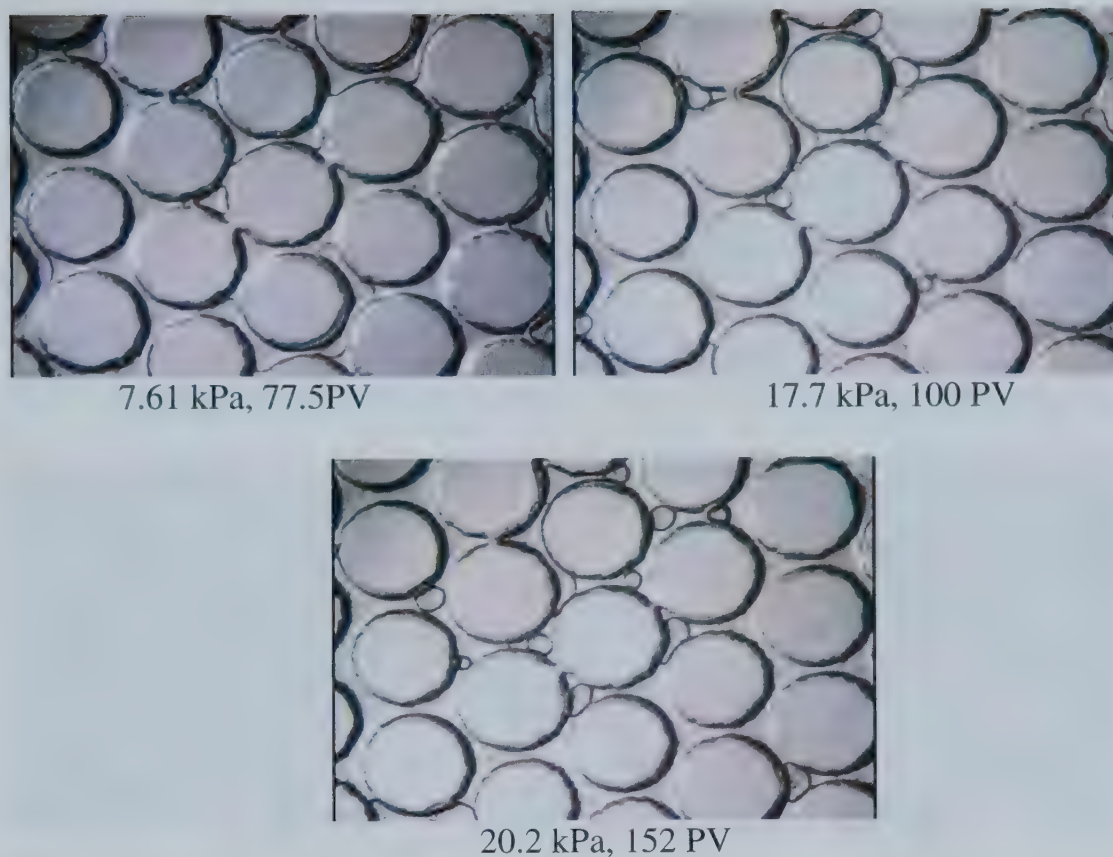


Figure C-2: Cont.

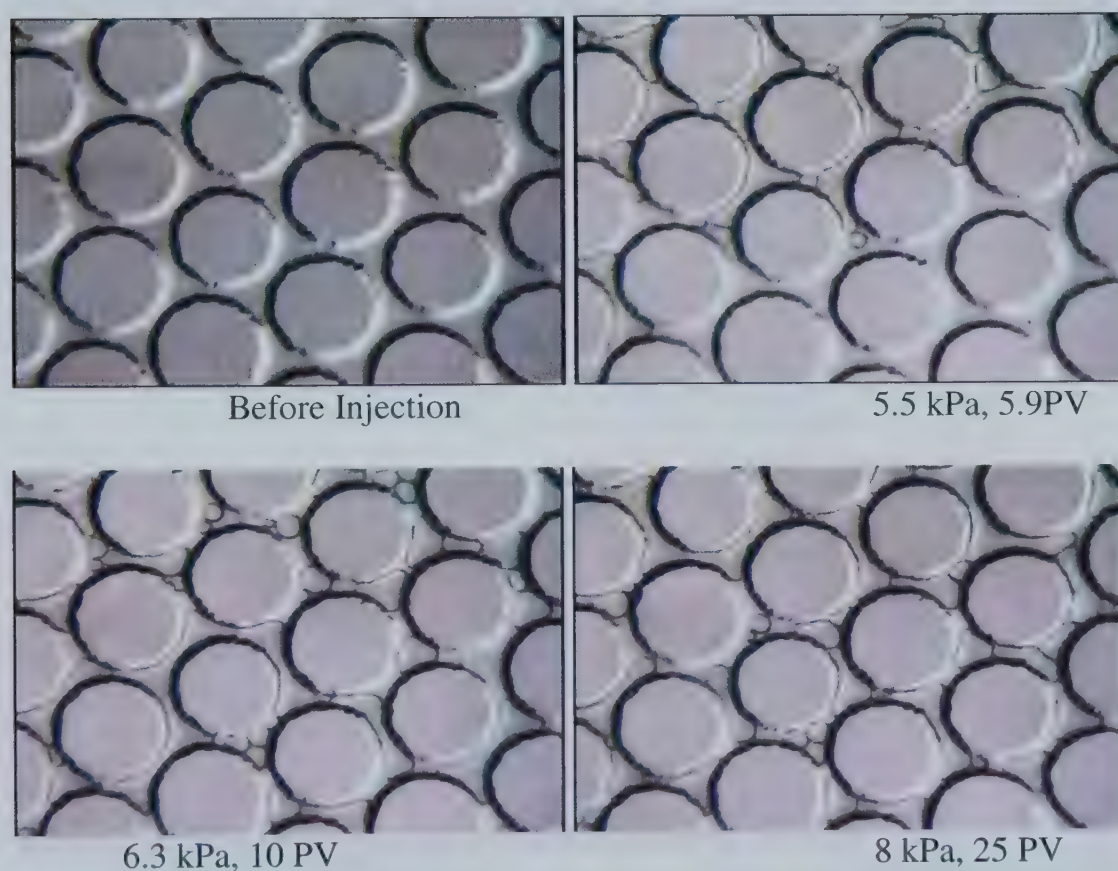
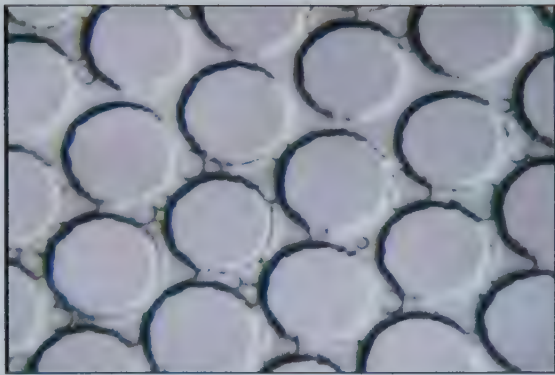
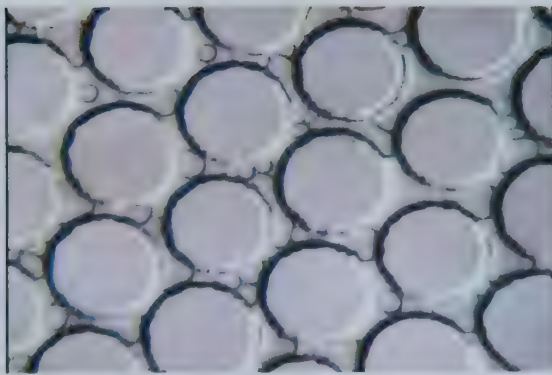


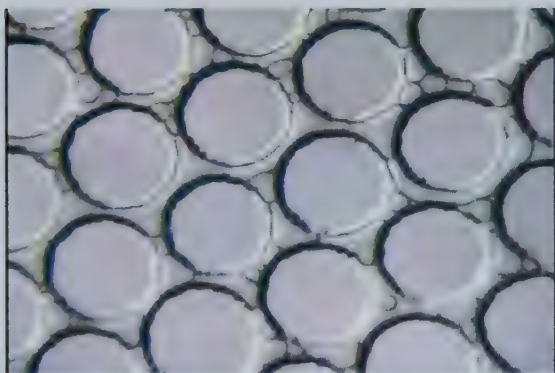
Figure C-3: Images of afoam flow through the microcell for W-P0.5-S2-R0.5-M1. Images taken at 1.6 x magnification.



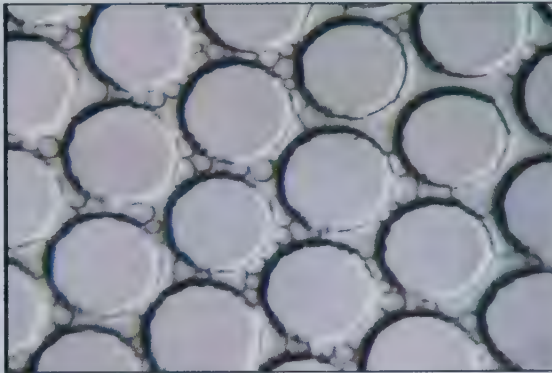
10 kPa, 45.6 PV



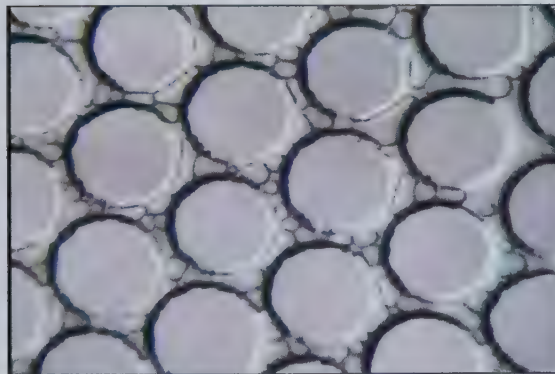
10.4 kPa, 50 PV



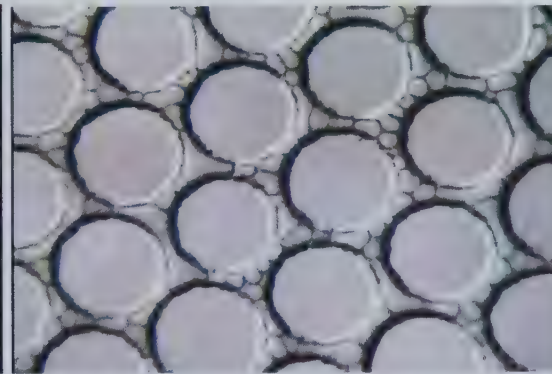
14.7 kPa, 100 PV



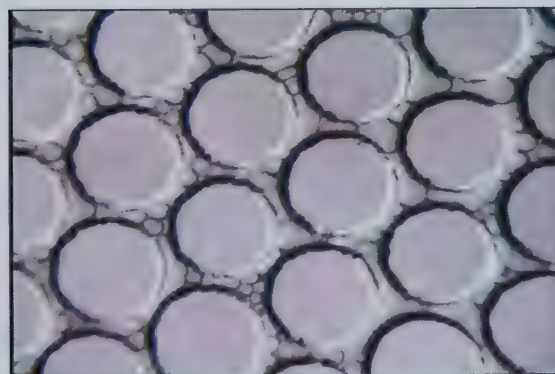
15 kPa, 104.4 PV



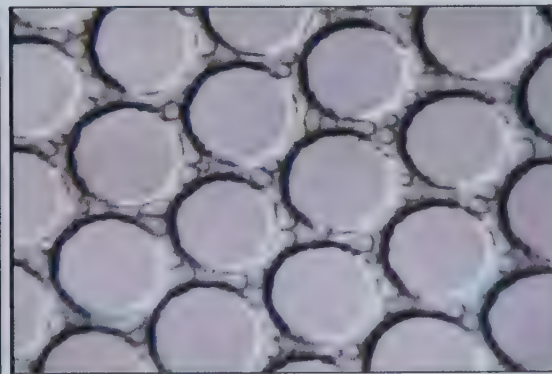
20 kPa, 158.8 PV



23.2 kPa, 200 PV

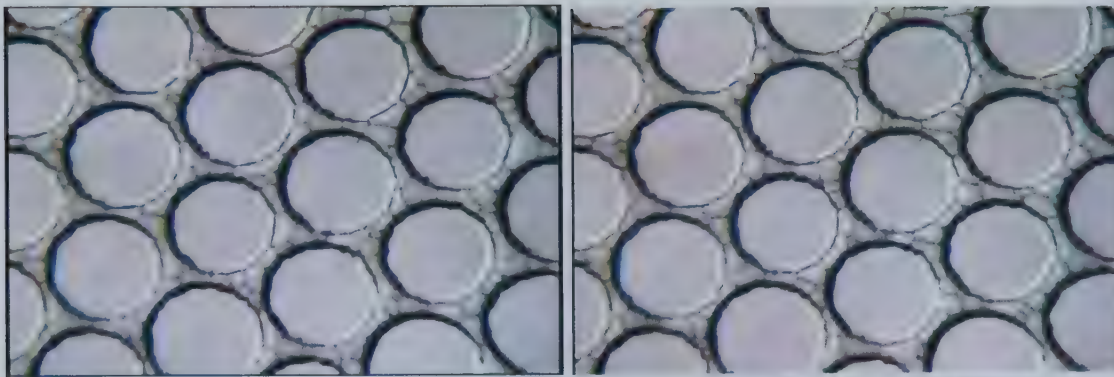


25 kPa, 222.5 PV



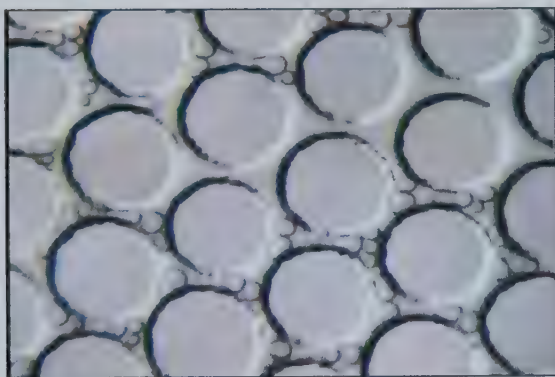
30 kPa, 267.15 PV

Figure C-3: Cont.

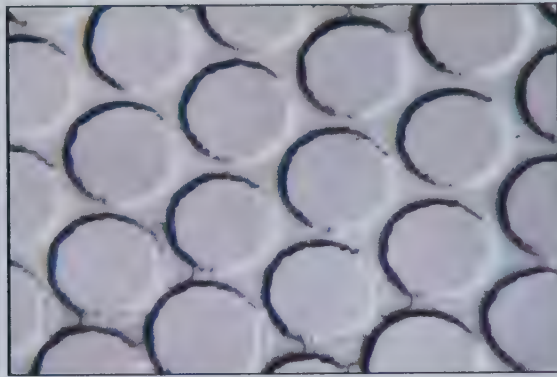


36.2 kPa, 390.7 PV

22.4 kPa, 400 PV

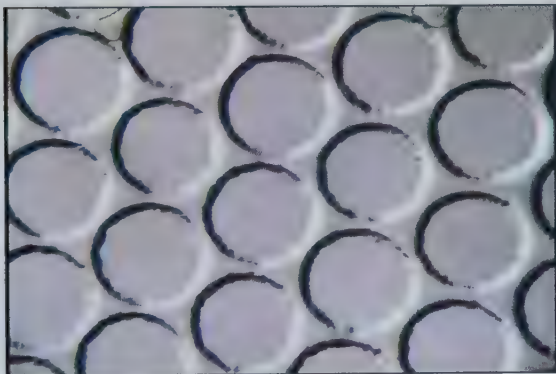


41.8 kPa, 405.4 PV

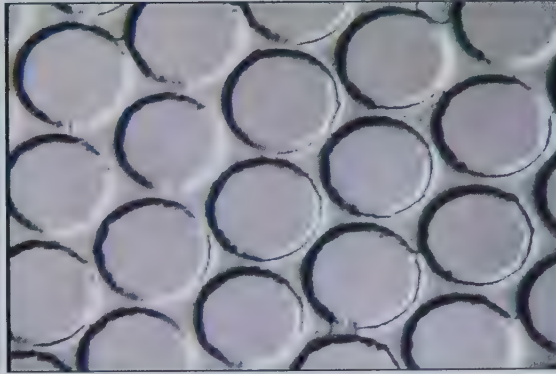


17.3 kPa, 575 PV

Figure C-3: Cont



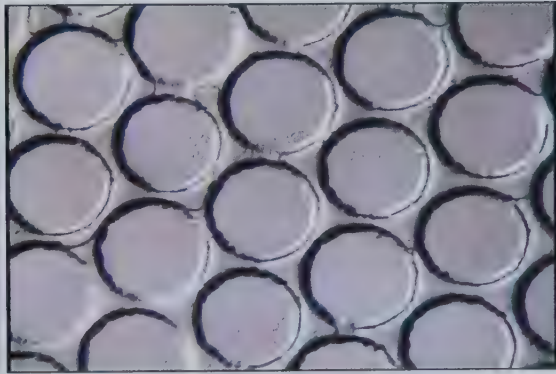
Before Injection



5.7 kPa, 0.5 PV

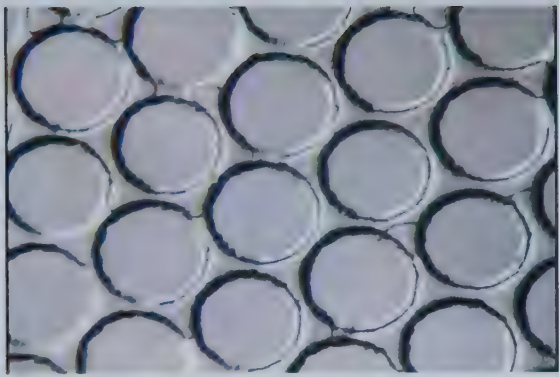


7.7 kPa, 10 PV

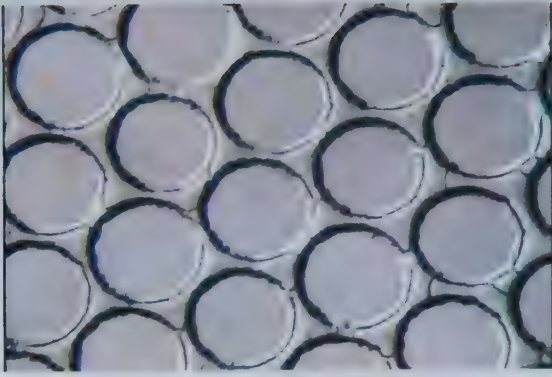


10 kPa, 20.1 PV

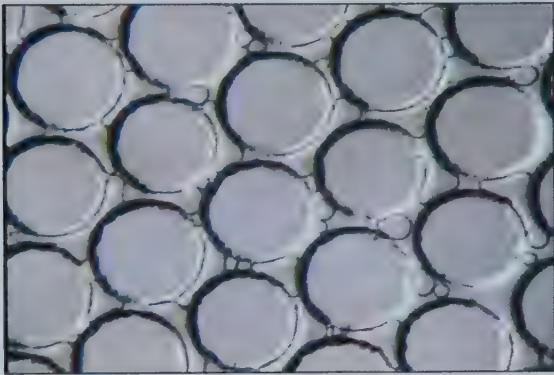
Figure C-4: Images of aphron flow through the microcell for W-P2-S2-R0.5-M1. Images taken at 1.6 x magnification.



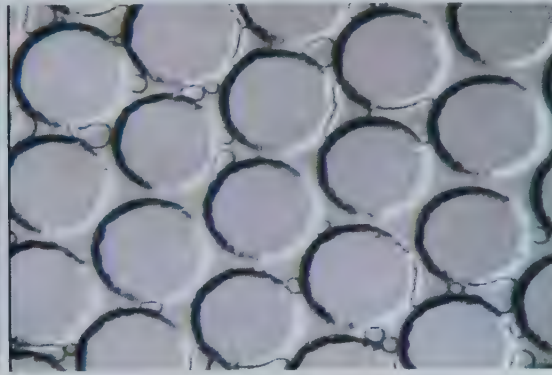
10.9 kPa, 25 PV



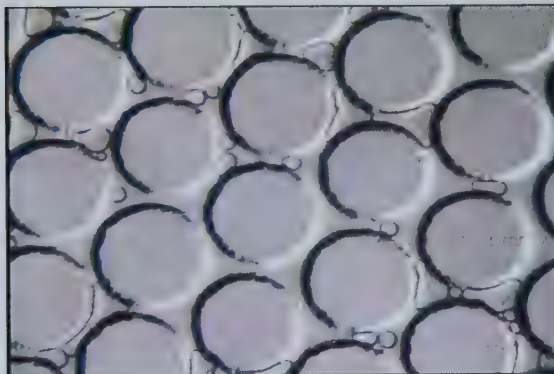
14.1 kPa, 50 PV



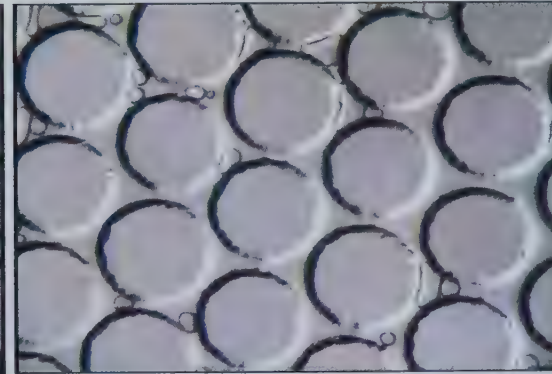
15 kPa, 58.3 PV



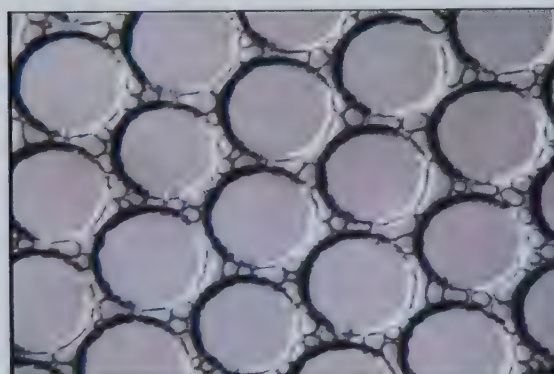
19.3 kPa, 100 PV



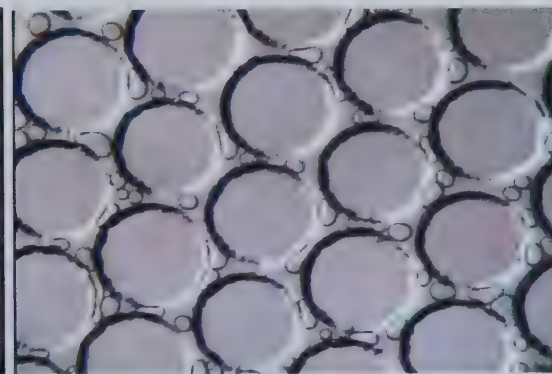
20 kPa, 107.4 PV



25 kPa, 155.9 PV

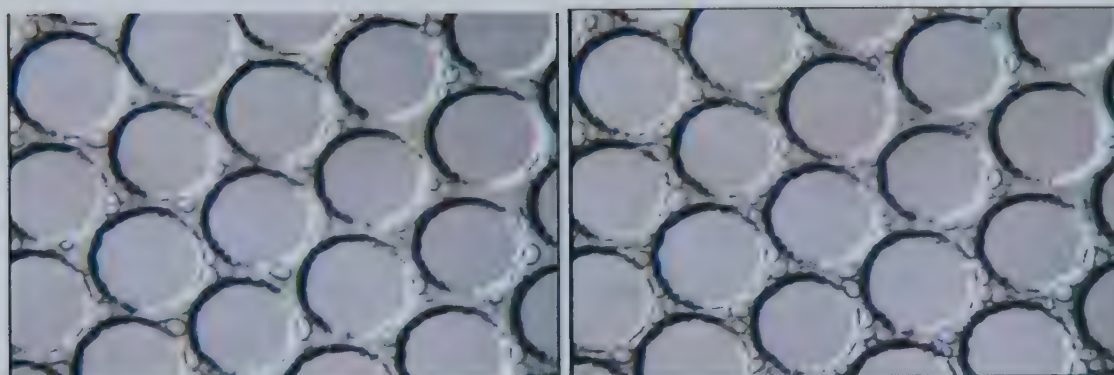


30 kPa, 200 PV



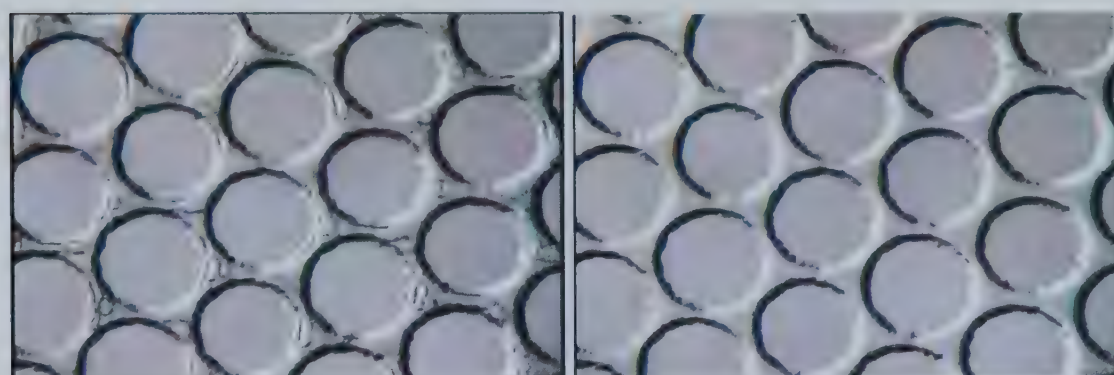
60.7 kPa, 400 PV

Figure C-4: Cont.



101.7 kPa, 600 PV

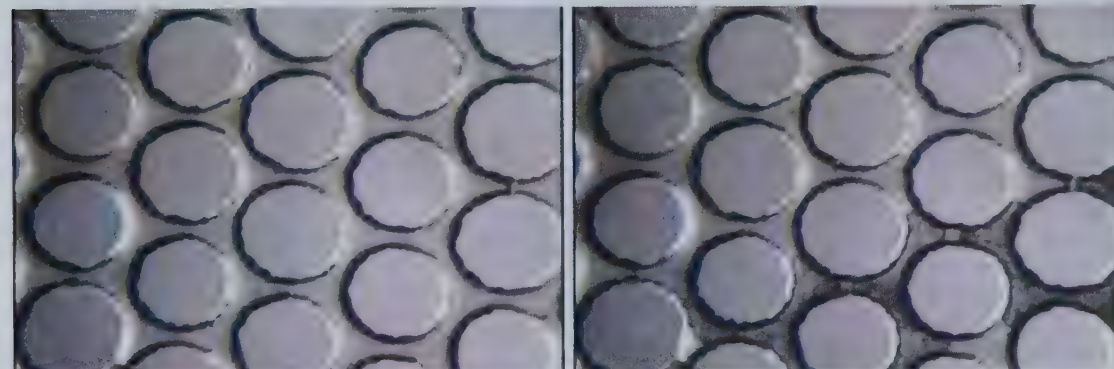
124 kPa, 684.3 PV



143 kPa, 686.8 PV

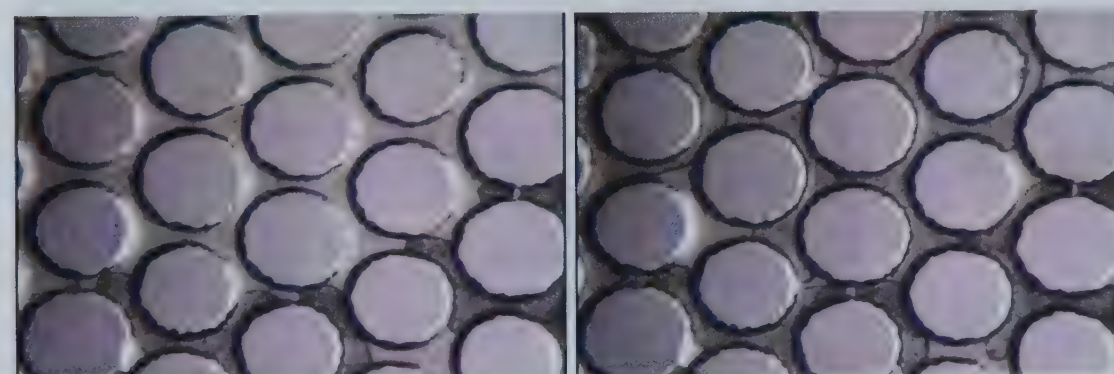
23.6 kPa, 994.6

Figure C-4: Cont.



Before Injection

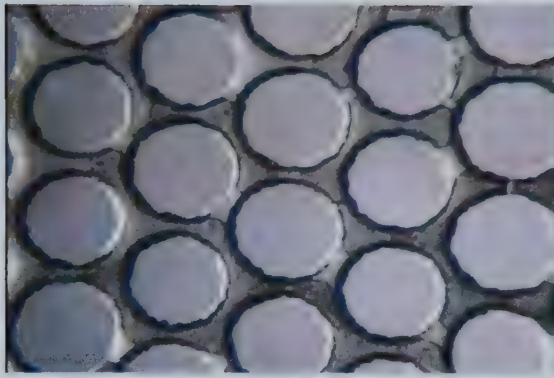
7.9 kPa, 0.5 PV



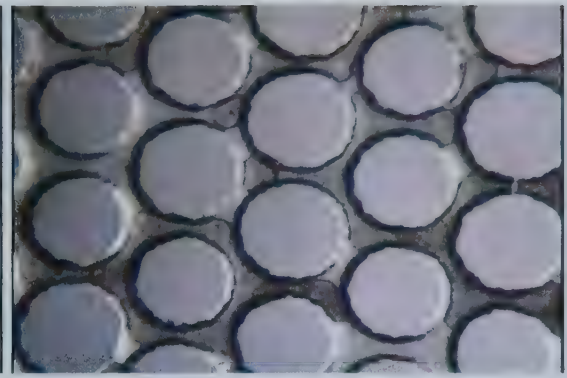
10 kPa, 10 PV

12.7 kPa, 25 PV

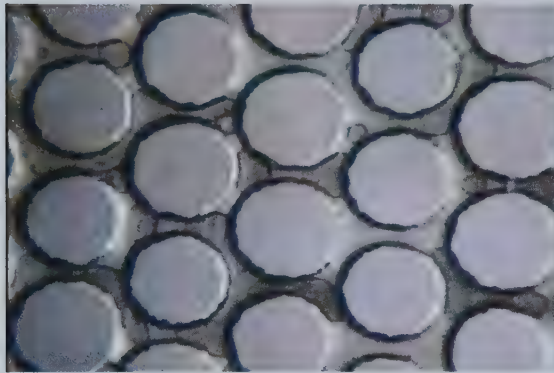
Figure C-5: Images of aphron flow through the microcell for W-P3-S2-R0.5-M1. Images taken at 1.6 x magnification.



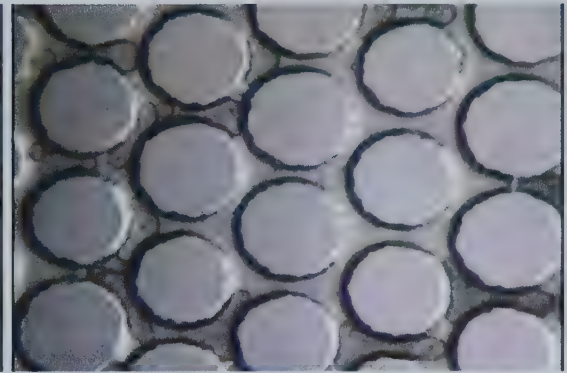
15 kPa, 44 PV



15.8 kPa, 50 PV



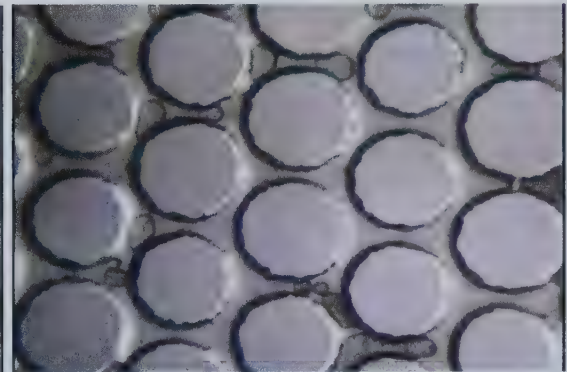
20 kPa, 94 PV



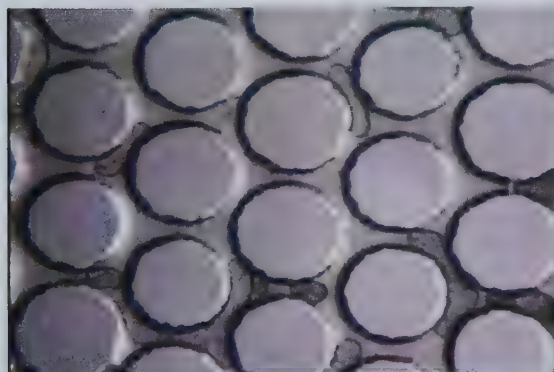
21.8 kPa, 100 PV



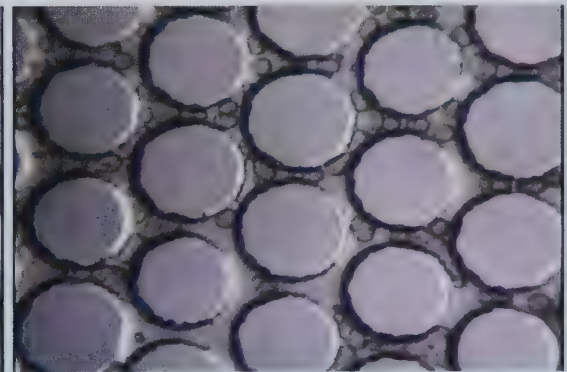
25 kPa, 124 PV



30 kPa, 159 PV

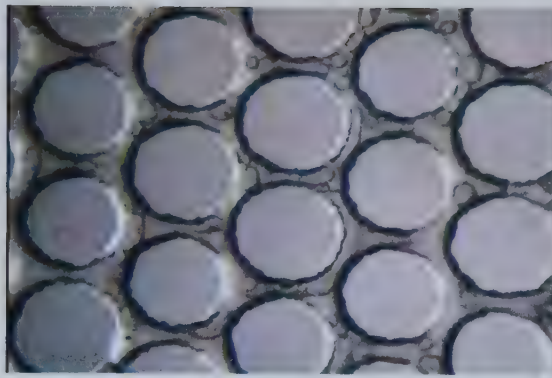


36.8 kPa, 200 PV

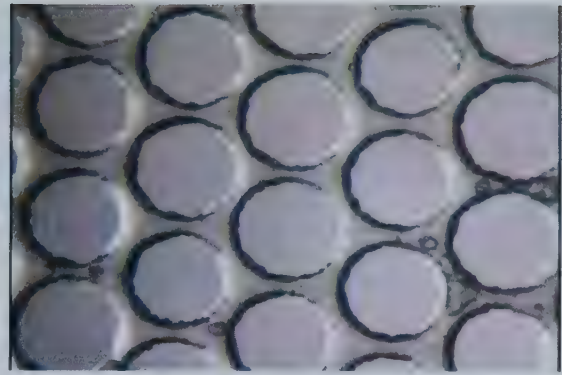


85.3 kPa, 400 PV

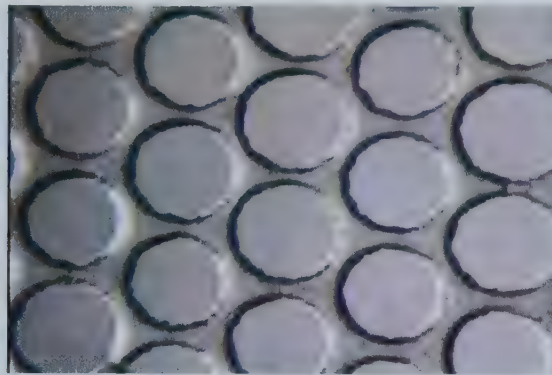
Figure C-5: Cont.



169 kPa, 576 PV



138.8 kPa, 600 PV

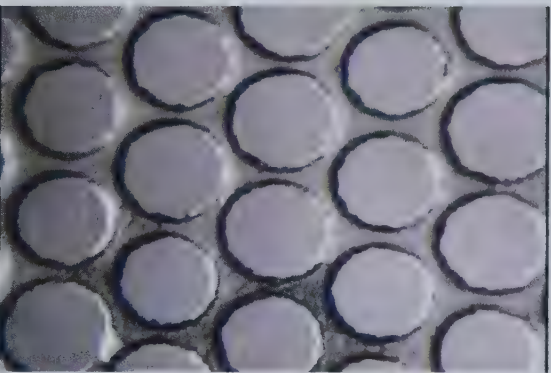


43 kPa, 717 PV

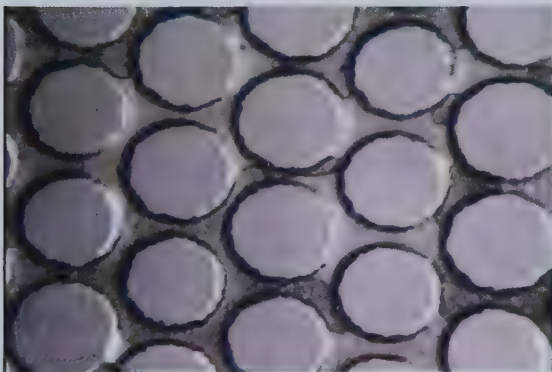
Figure C-5: Cont.



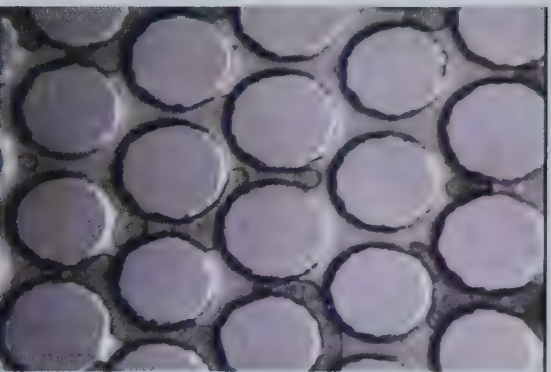
Before Injection



11.4 kPa, 0.5 PV

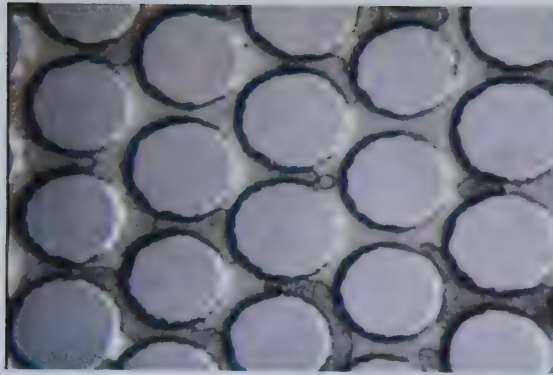


15 kPa, 10 PV

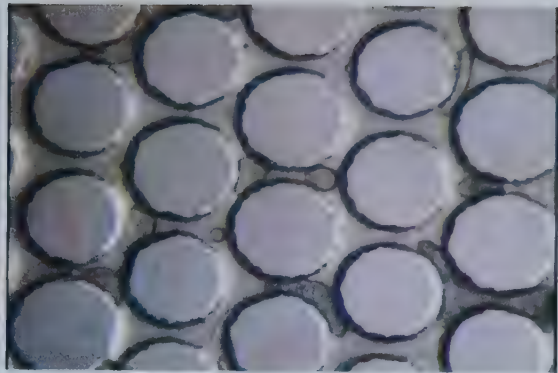


20 kPa, 23 PV

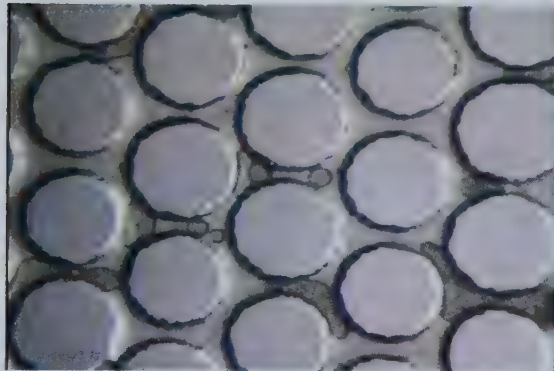
Figure C-6: Images of aphron flow through the microcell for W-P3-S0-R0.5-M1. Images taken at 1.6 x magnification.



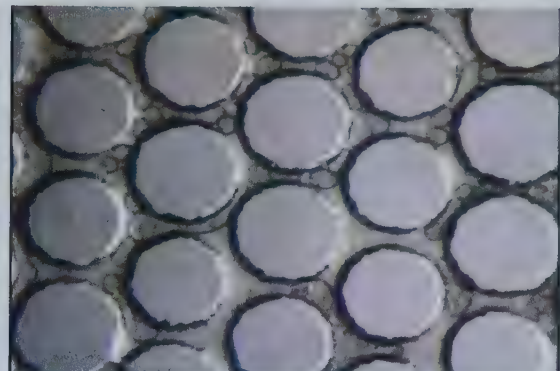
20.6 kPa, 25 PV



25 kPa, 37 PV



30 kPa, 50 PV



55 kPa, 100 PV



144 kPa, 200 PV



150 kPa, 205 PV

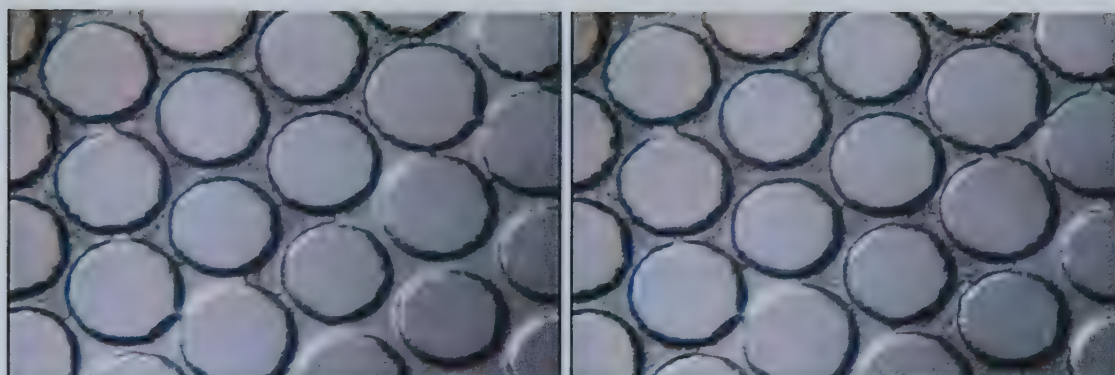


46 kPa, 400 PV



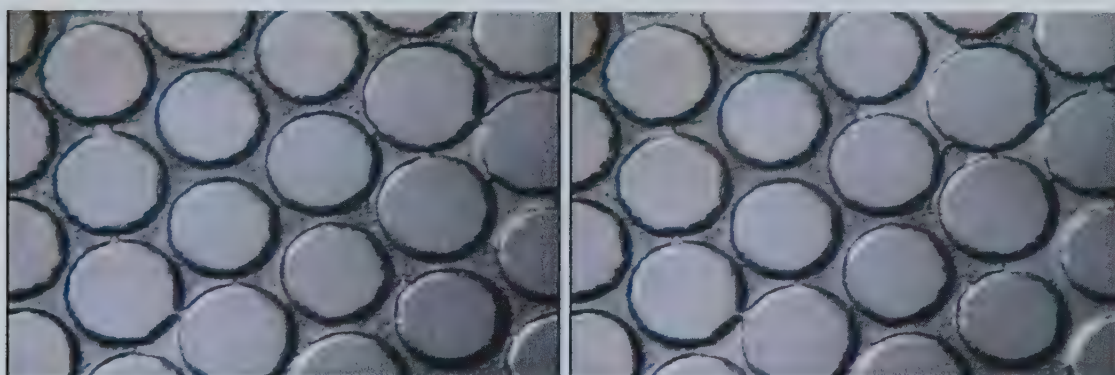
44 kPa, 488PV

Figure C-6: Cont.



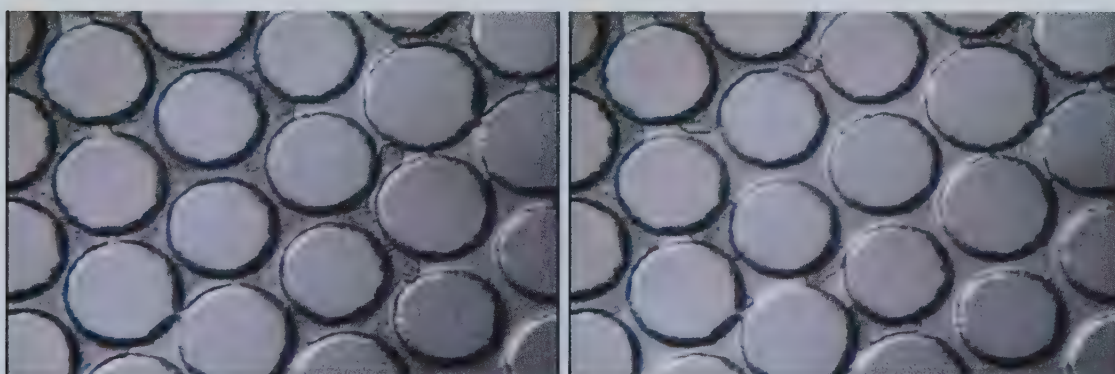
8 kPa, 0.5 PV

10 kPa, 4 PV



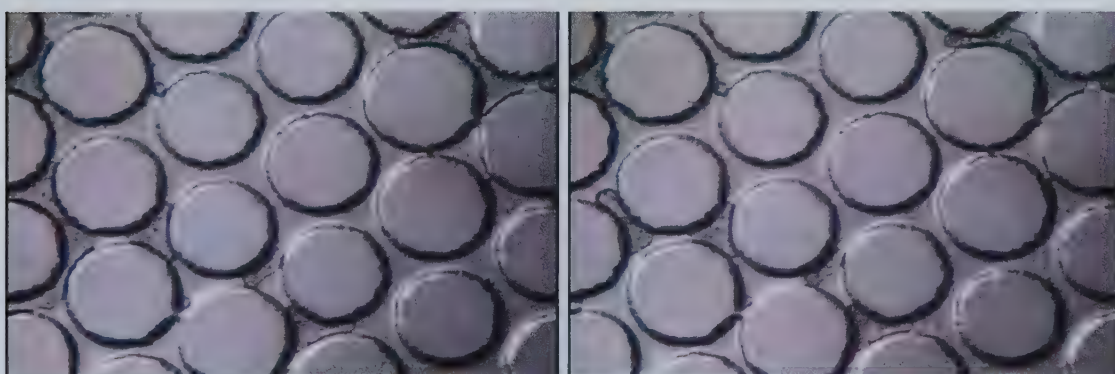
11.8 kPa, 10 PV

15 kPa, 23 PV



15.6 kPa, 25 PV

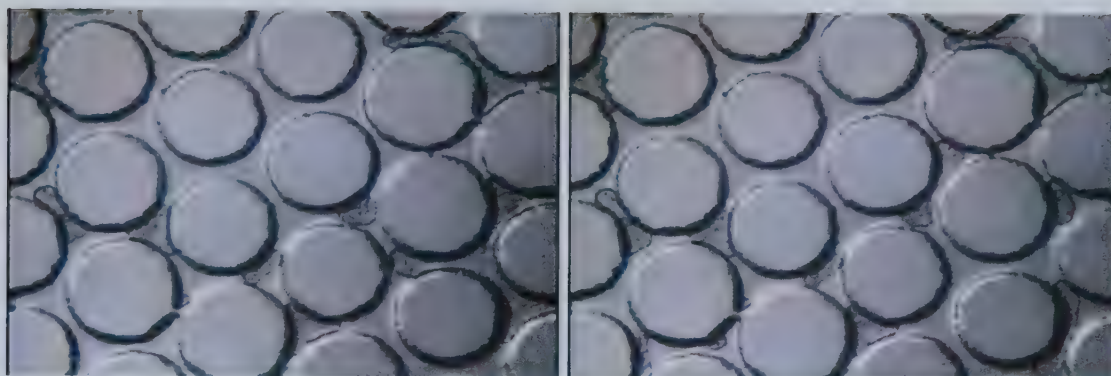
20 kPa, 44PV



21.6 kPa, 50 PV

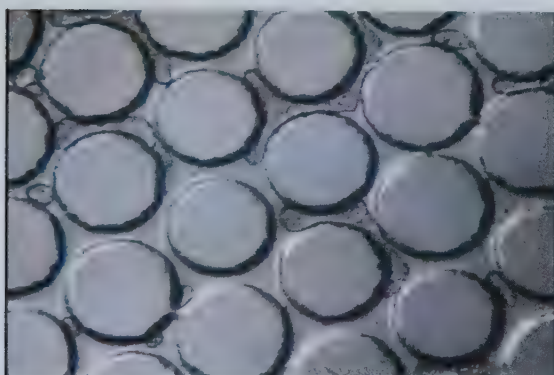
25 kPa, 62 PV

Figure C-7: Images of aphron flow through the microcell for W-P3-S0.035-R0.5-M1. Images taken at 1.6 x magnification.

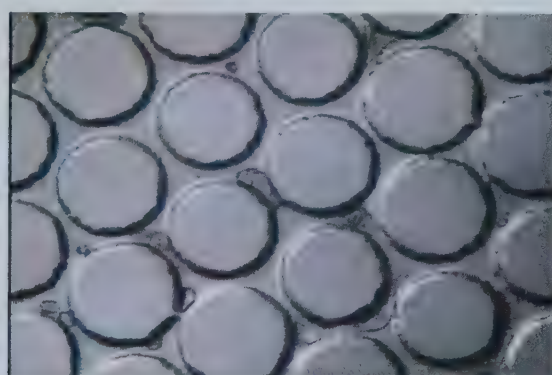


30 kPa, 79 PV

36.6 kPa, 100 PV



79.4 kPa, 200 PV



191 kPa, 364 PV



112.5 kPa, 400 PV



52 kPa, 520PV

Figure C-7: Cont.

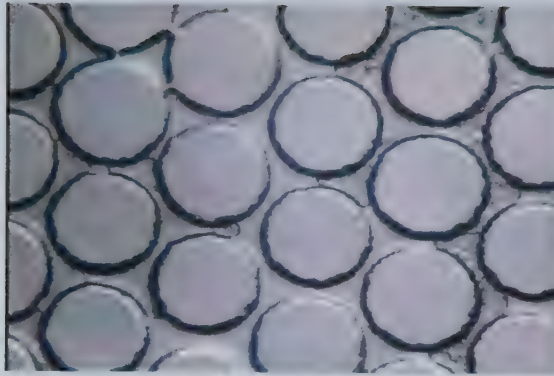


Before Injection

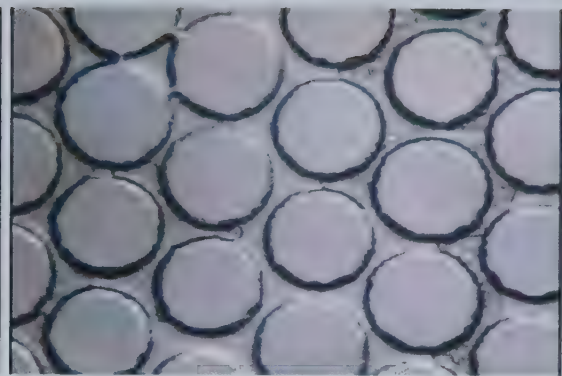


7.5 kPa, 0.5 PV

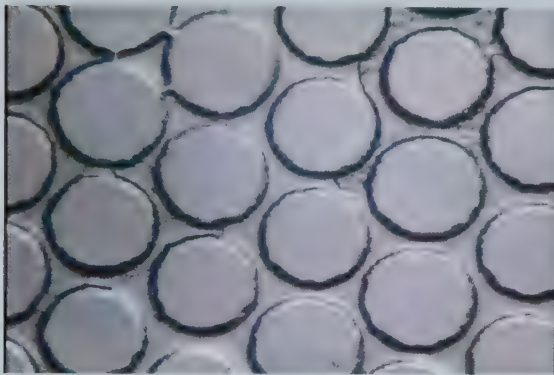
Figure C-8: Images of aphron flow through the microcell for W-P2-S1-R0.5-M1. Images taken at 1.6 x magnification.



9.5 kPa, 10 PV



10 kPa, 13 PV



11.6 kPa, 25 PV



14 kPa, 50 PV



15 kPa, 60PV



18.5 kPa, 100 PV

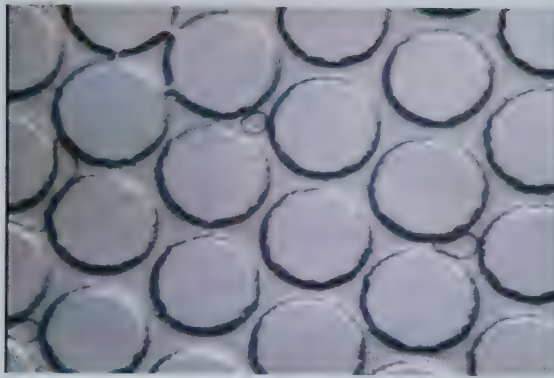


20 kPa, 117 PV

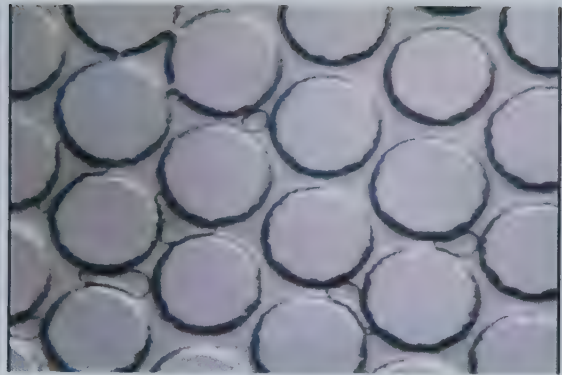


25 kPa, 167PV

Figure C-8: Cont.



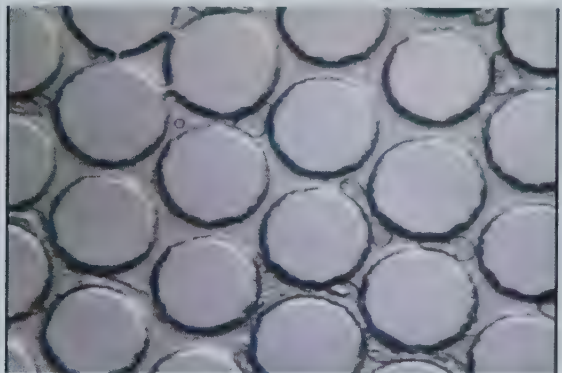
28 kPa, 200 PV



30 kPa, 241 PV



54 kPa, 400 PV



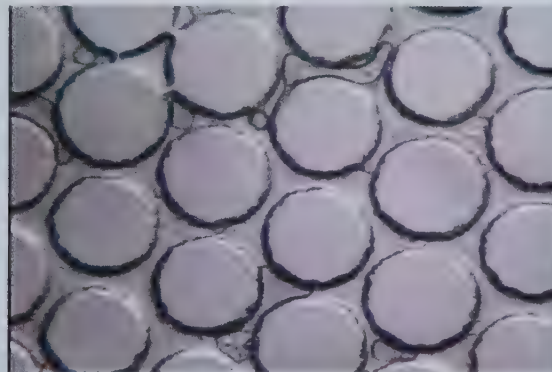
90.8 kPa, 600 PV



103 kPa, 655 PV

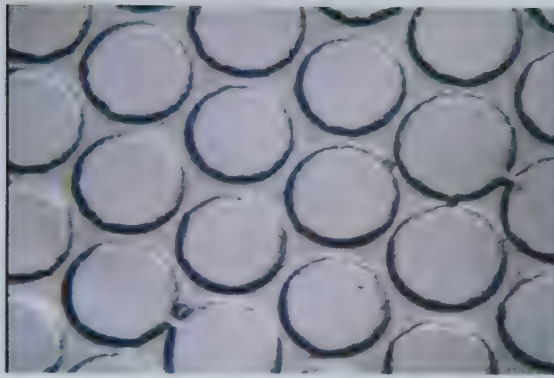


45.7 kPa, 800 PV

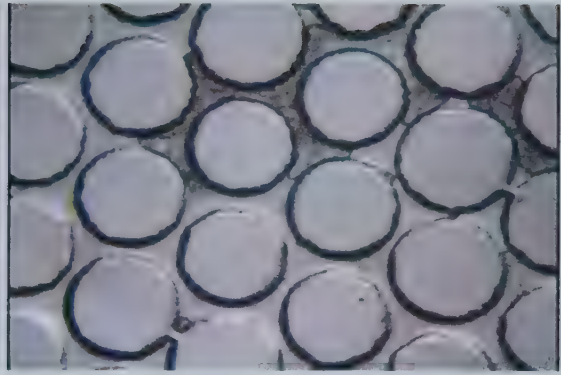


42 kPa, 1090 PV

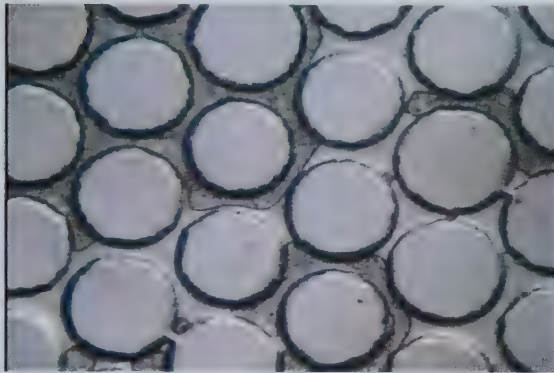
Figure C-8: Cont.



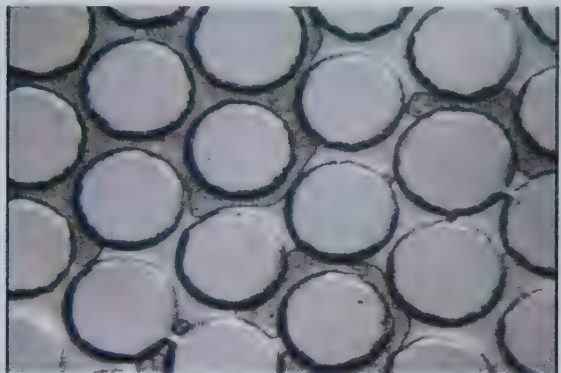
Before Injection



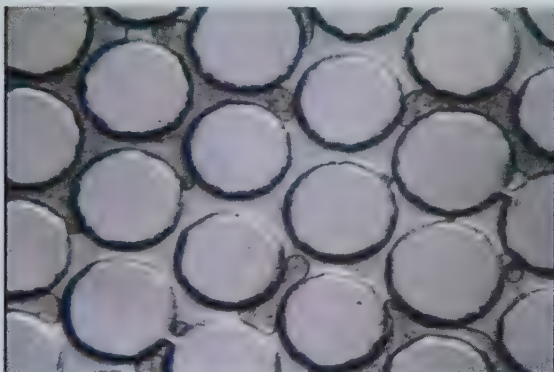
8 kPa, 0.5 PV



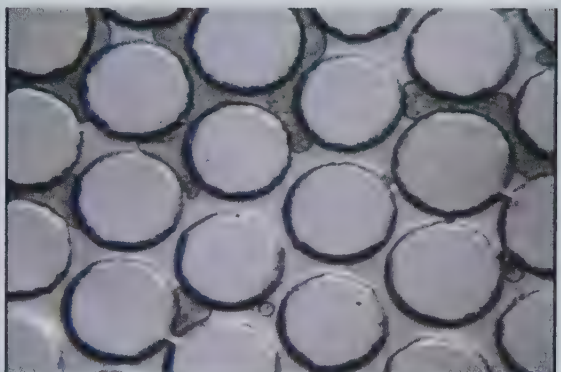
10 kPa, 10 PV



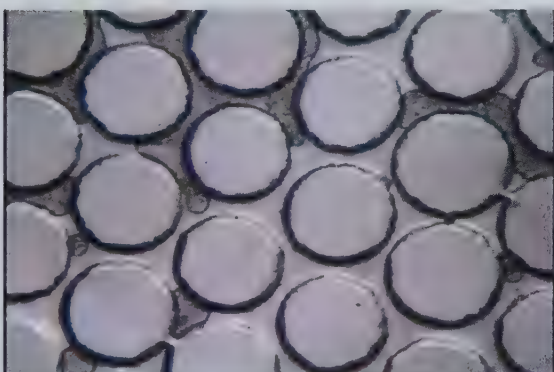
12 kPa, 25PV



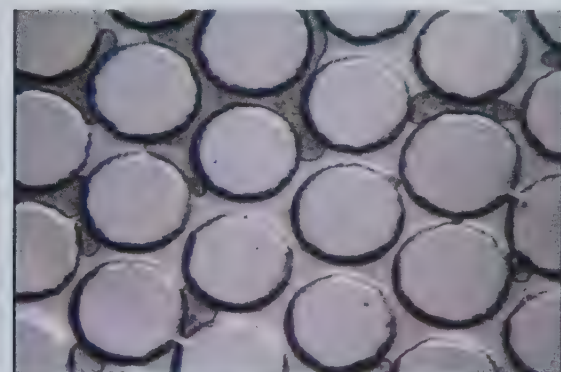
15 kPa, 50PV



20 kPa, 88 PV

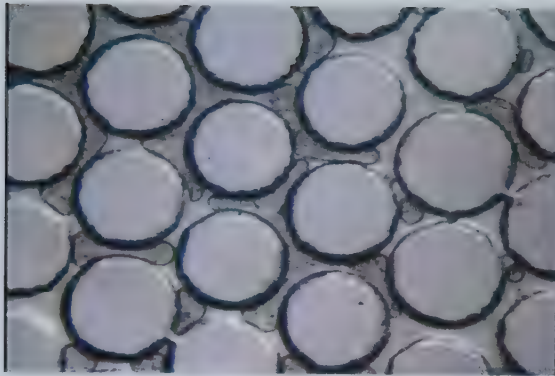


22 kPa, 100 PV

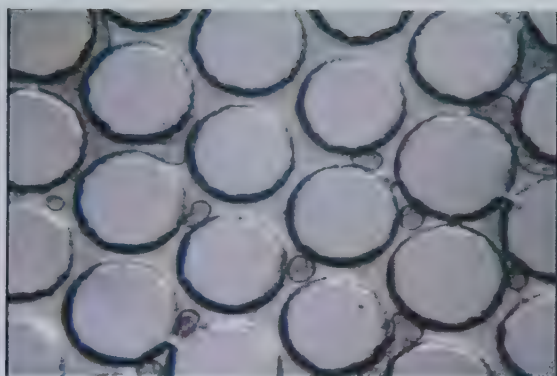


25 kPa, 122PV

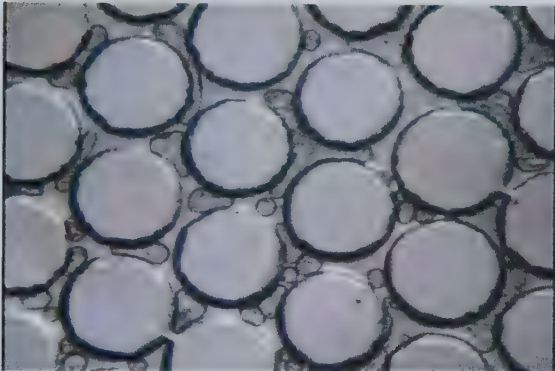
Figure C-9: Images of aphron flow through the microcell for W-P1-S0.035-R0.5-M1. Images taken at 1.6 x magnification.



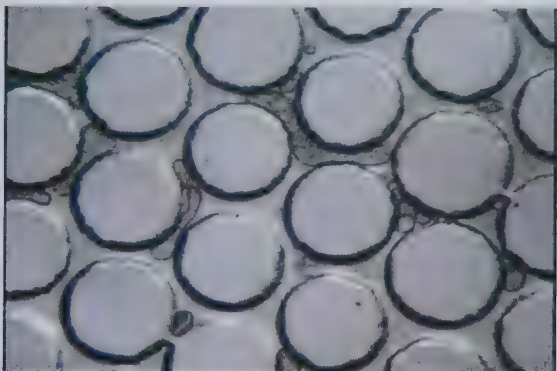
30 kPa, 155 PV



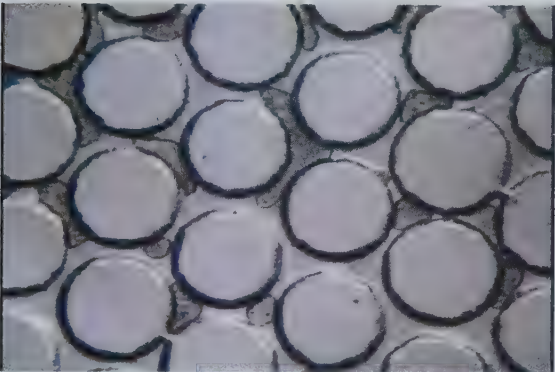
37.6 kPa, 200 PV



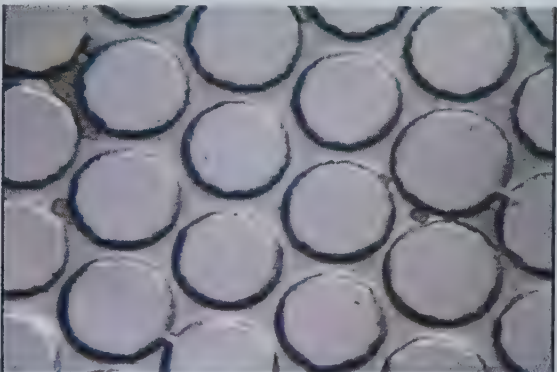
80.3 kPa, 400PV



94 kPa, 462PV



51.3 kPa, 600 PV



45 kPa, 805 PV

Figure C-9: Cont.

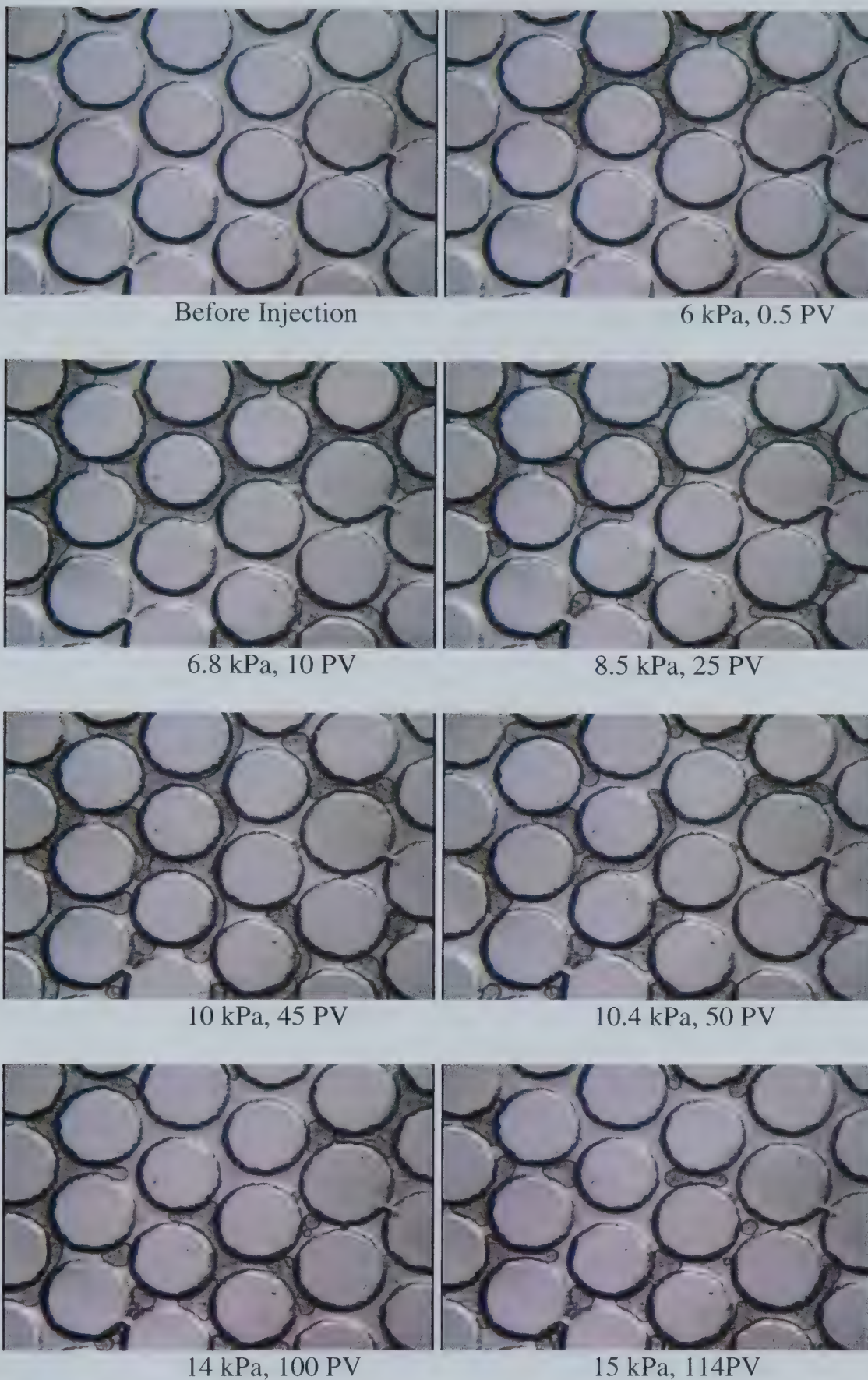
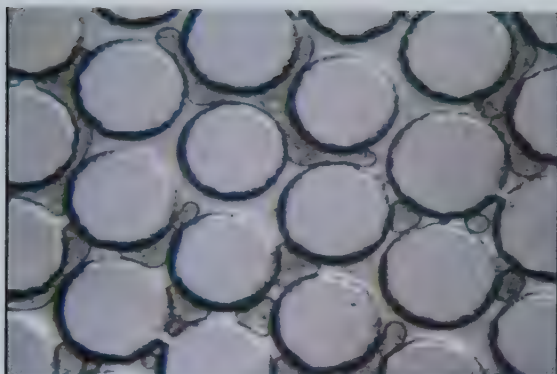
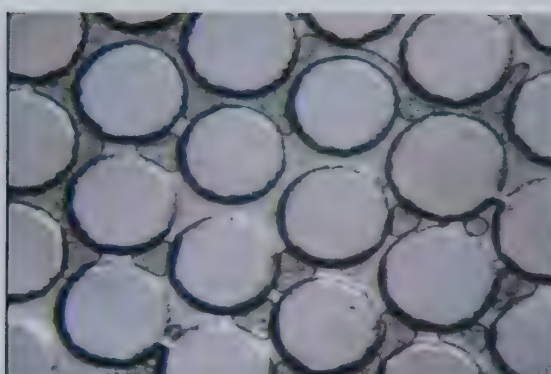


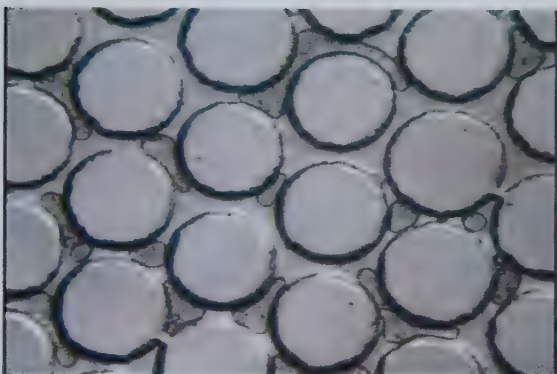
Figure C-10: Images of afoam flow through the microcell for W-P1-S1-R0.5-M1. Images taken at 1.6 x magnification.



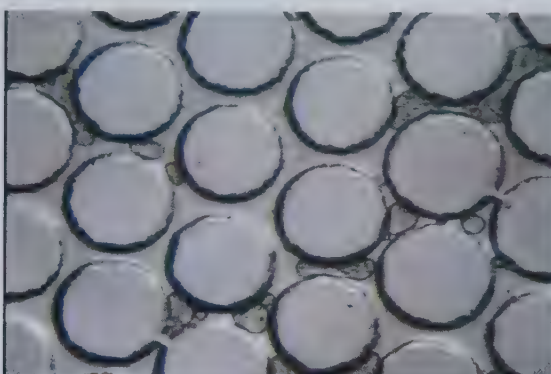
20 kPa, 181 PV



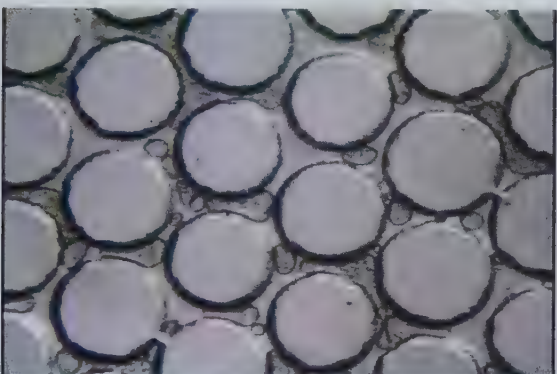
21.6 kPa, 200PV



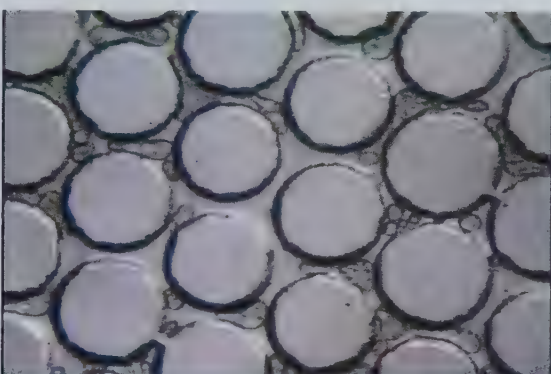
25 kPa, 240 PV



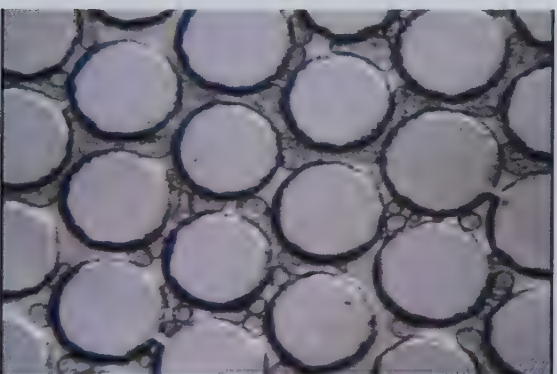
30 kPa, 295 PV



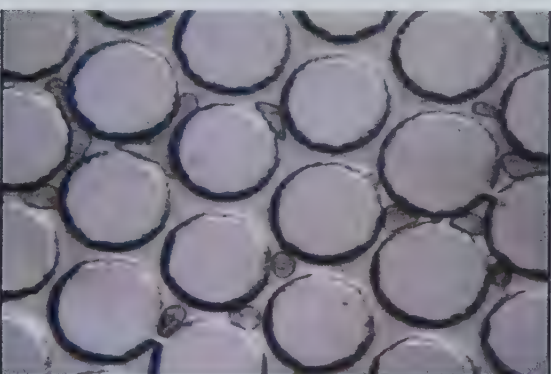
40.3 kPa, 400 PV



63 kPa, 600PV

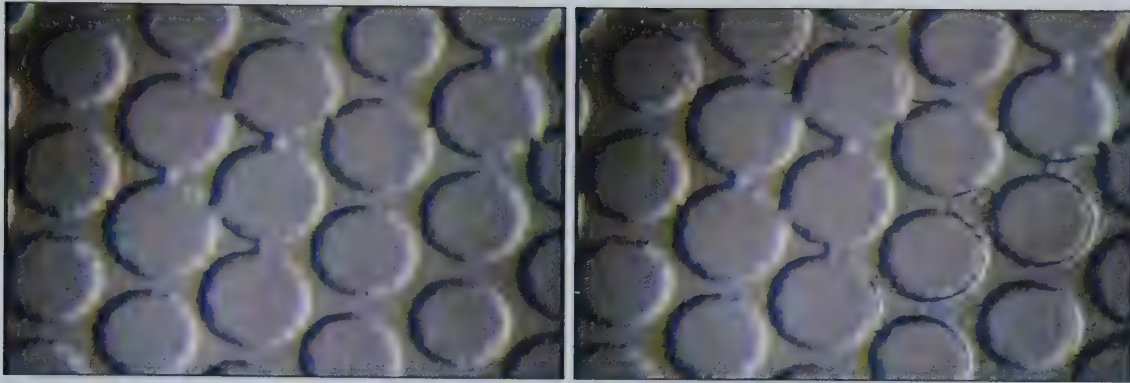


66 kPa, 646PV

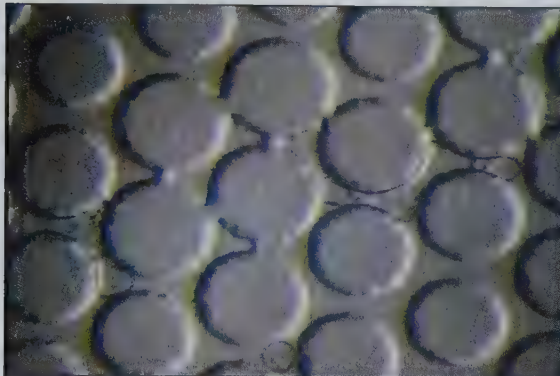


62 kPa, 700 PV

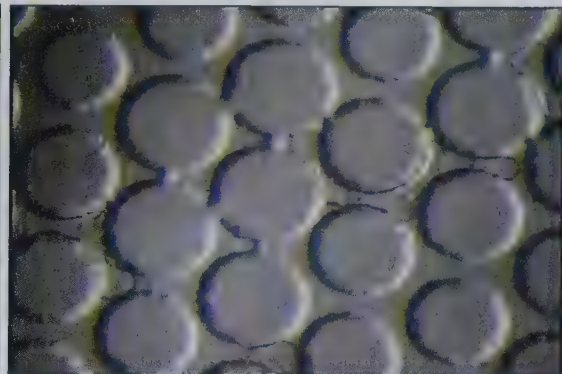
Figure C-10 Cont.



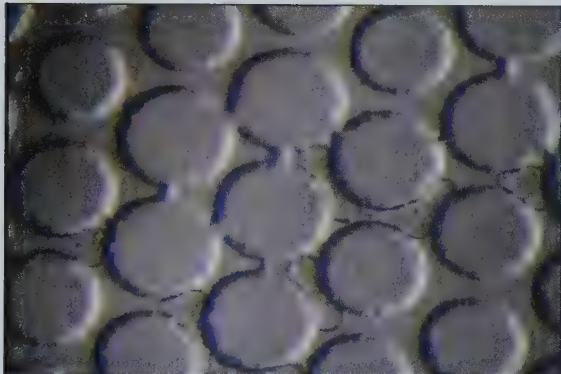
Before Injection During pressure build-up, before foam injection 11.6 kPa,



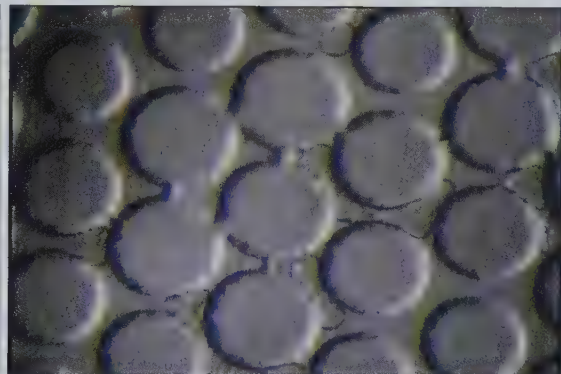
15 kPa, 84.3 PV



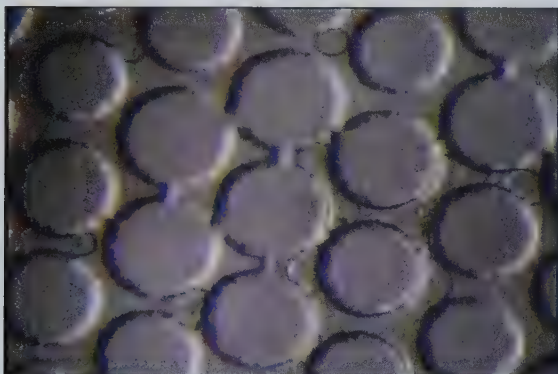
20 kPa, 241.7 PV



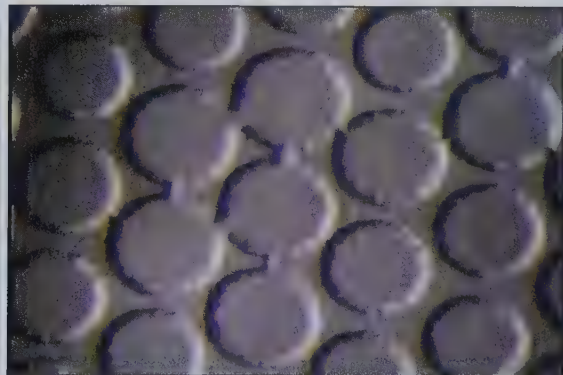
25 kPa, 397.2 kPa



30 kPa, 434.3 PV



51.6 kPa, 441.7 PV



132.2 kPa, 555.6 PV

Figure C-11: Images of aphron flow through the microcell for W-P0.5-S1-R0.5-M2. Images taken at 1.6 x magnification.

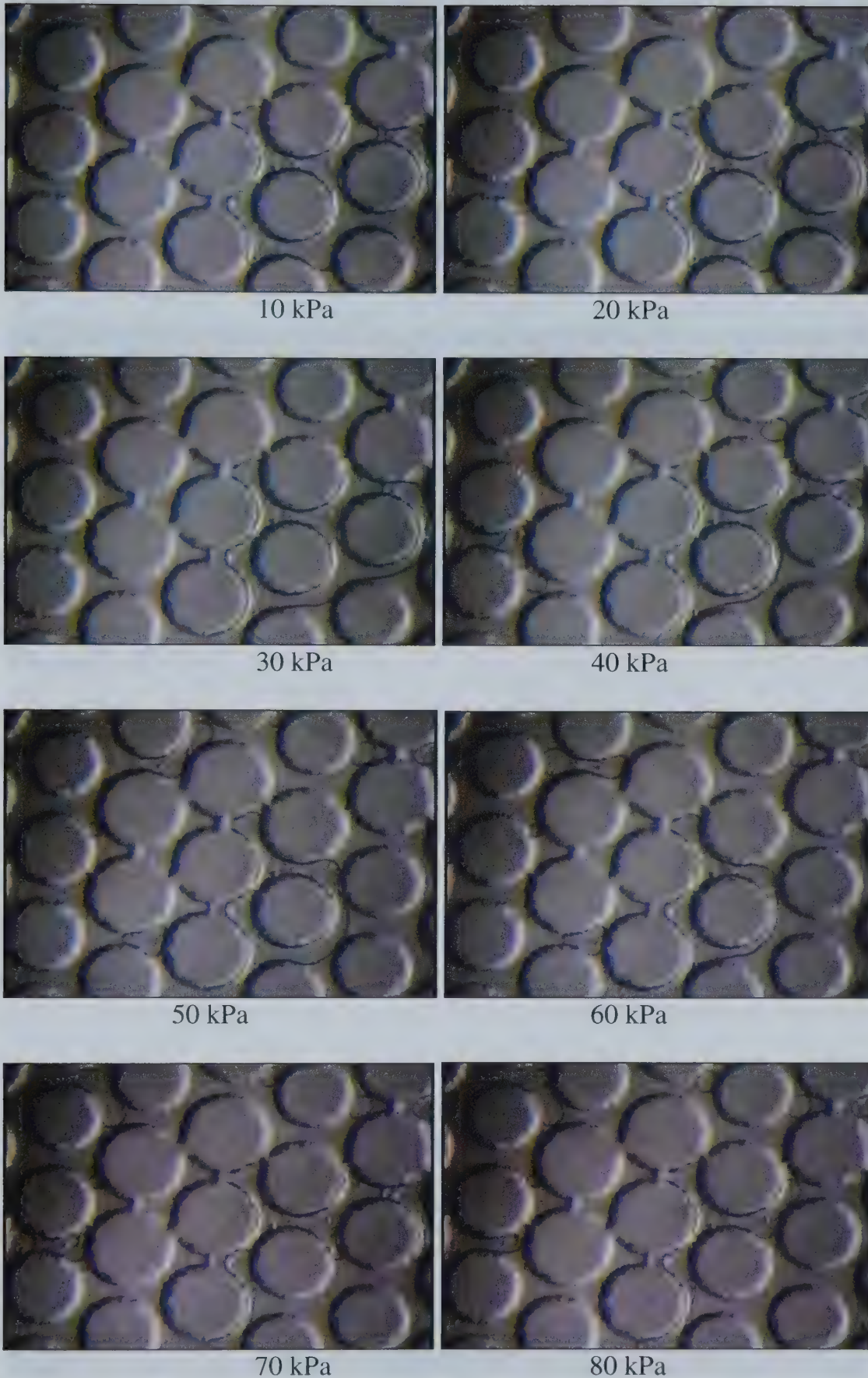


Figure C-12: Images of aperiodic flow through the microcell for W-P0.5-S1-R(Varied)-M2. Images taken at 4.0 x magnification.

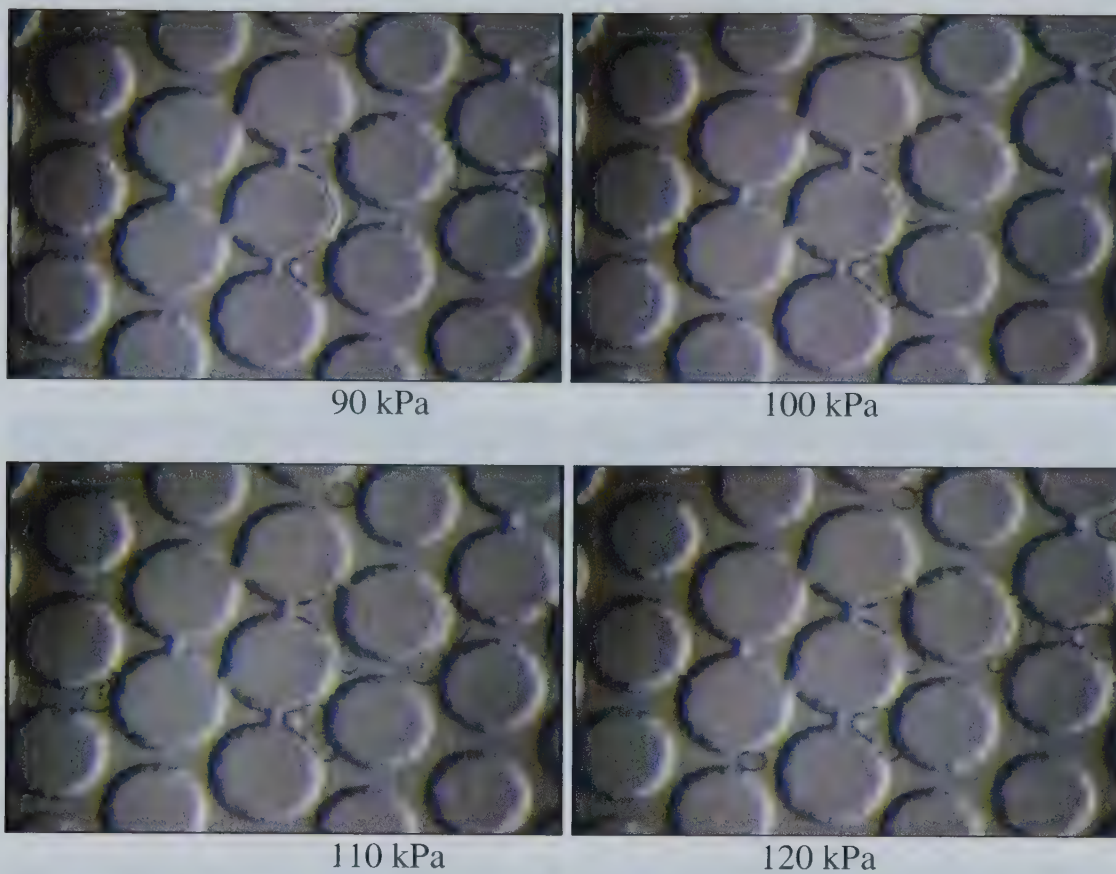


Figure C-12: Cont.

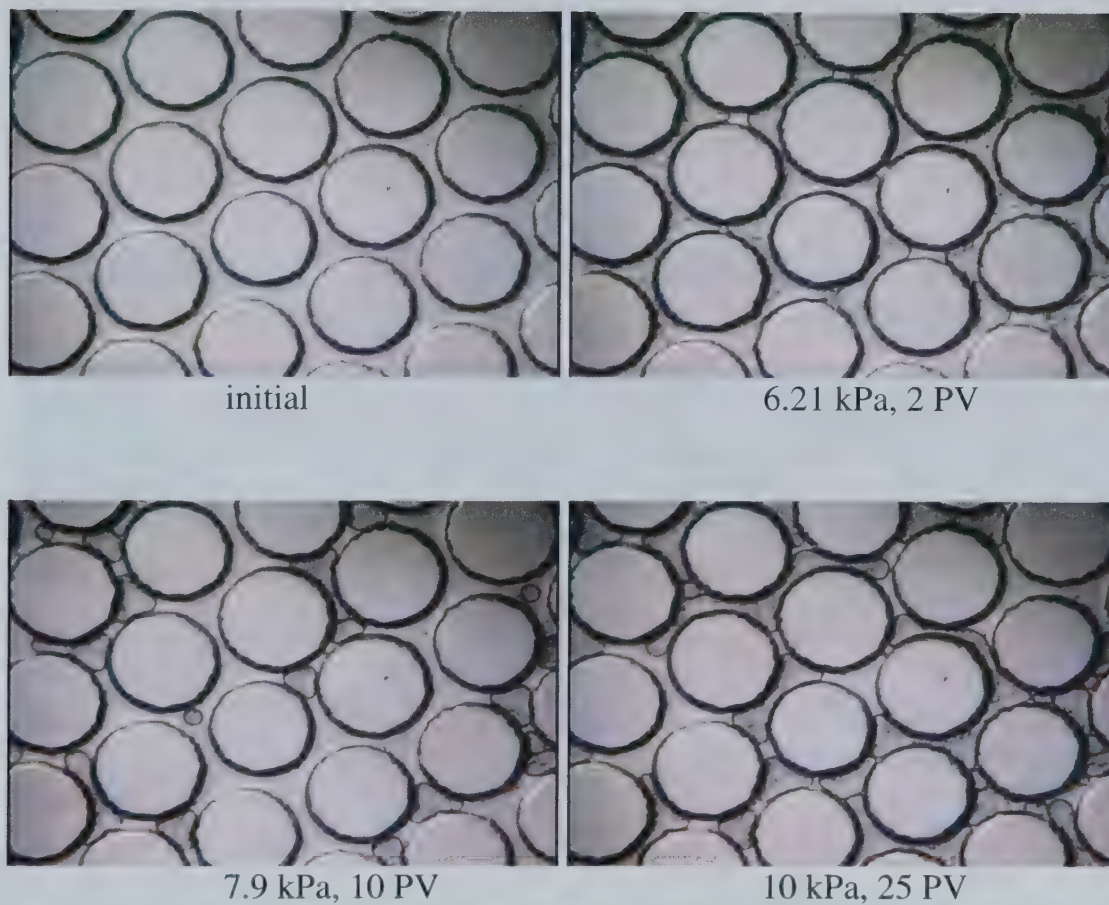
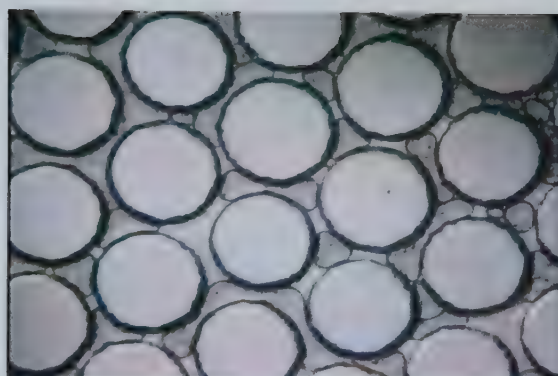
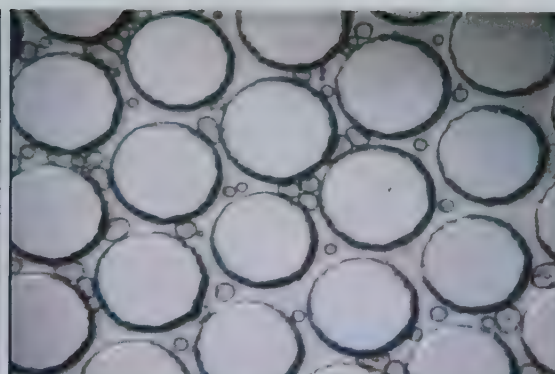


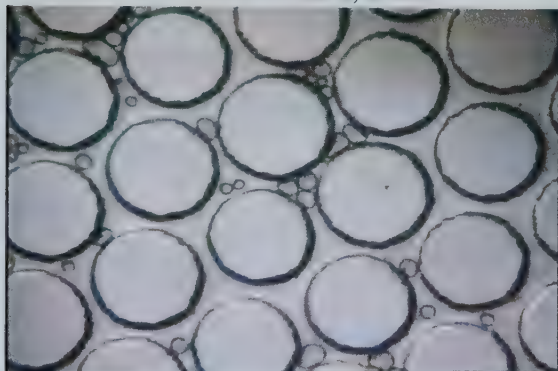
Figure C-13: Images of afoam flow through the microcell for B-P1-S2-R1-M1. Images taken at 1.6 x magnification.



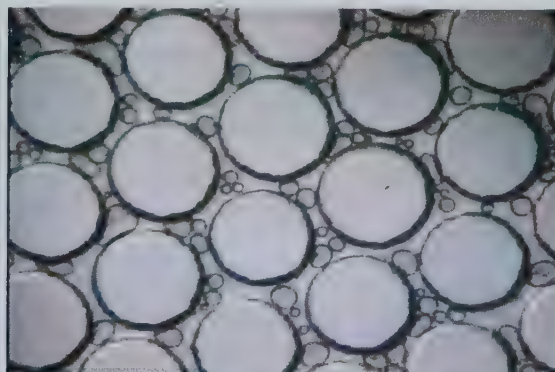
12.2 kPa, 50 PV



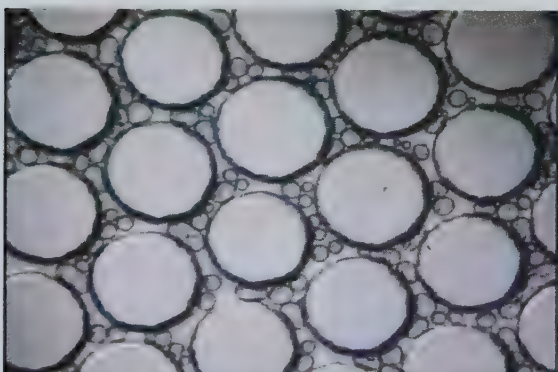
15 kPa 83 PV



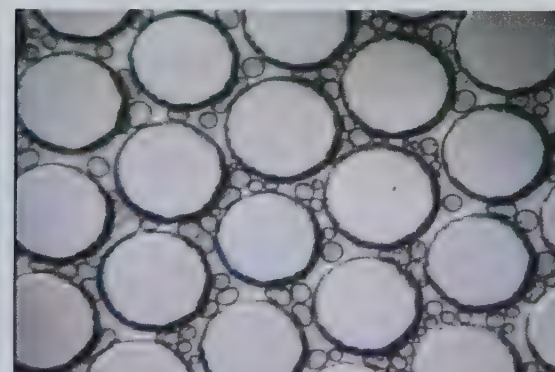
16.3 kPa 100 PV



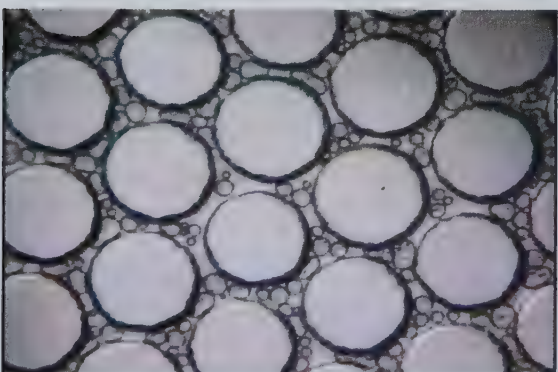
20 kPa 142 PV



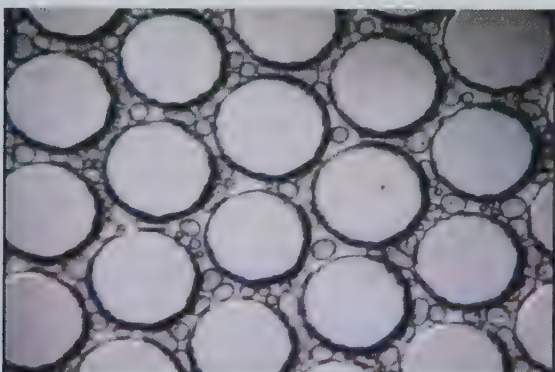
25 kPa, 197 PV



25.3 kPa, 200 PV

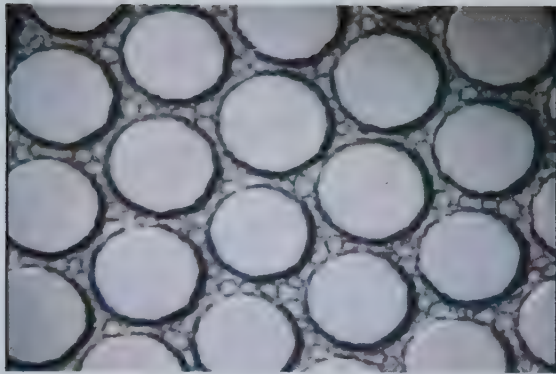


30 kPa 242 PV

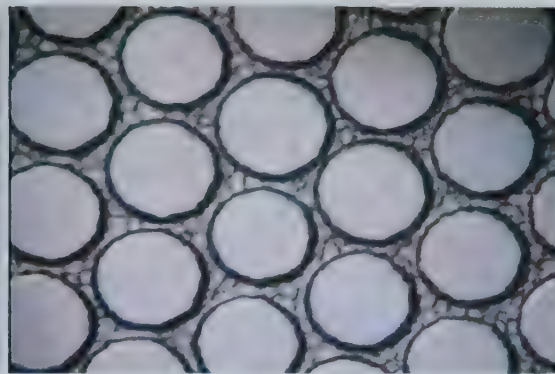


46.9 kPa, 400 PV

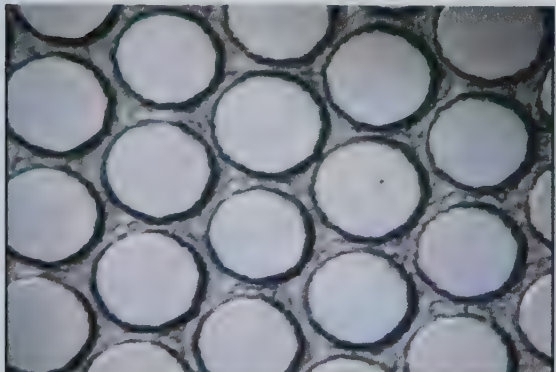
Figure C-13: Cont.



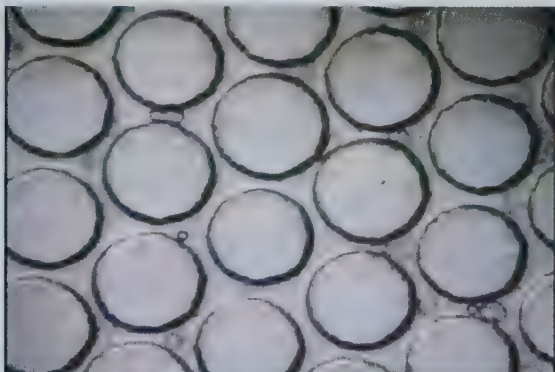
77 kPa 600 PV



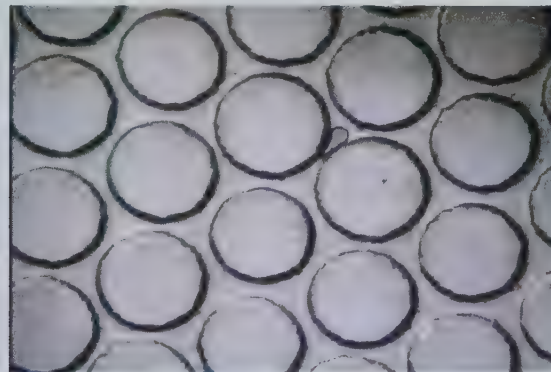
90.31 kPa, 673 PV



200 kPa, 718 PV



43.4 kPa 800 PV



40.67 kPa 837 PV

Figure C-13: Cont.

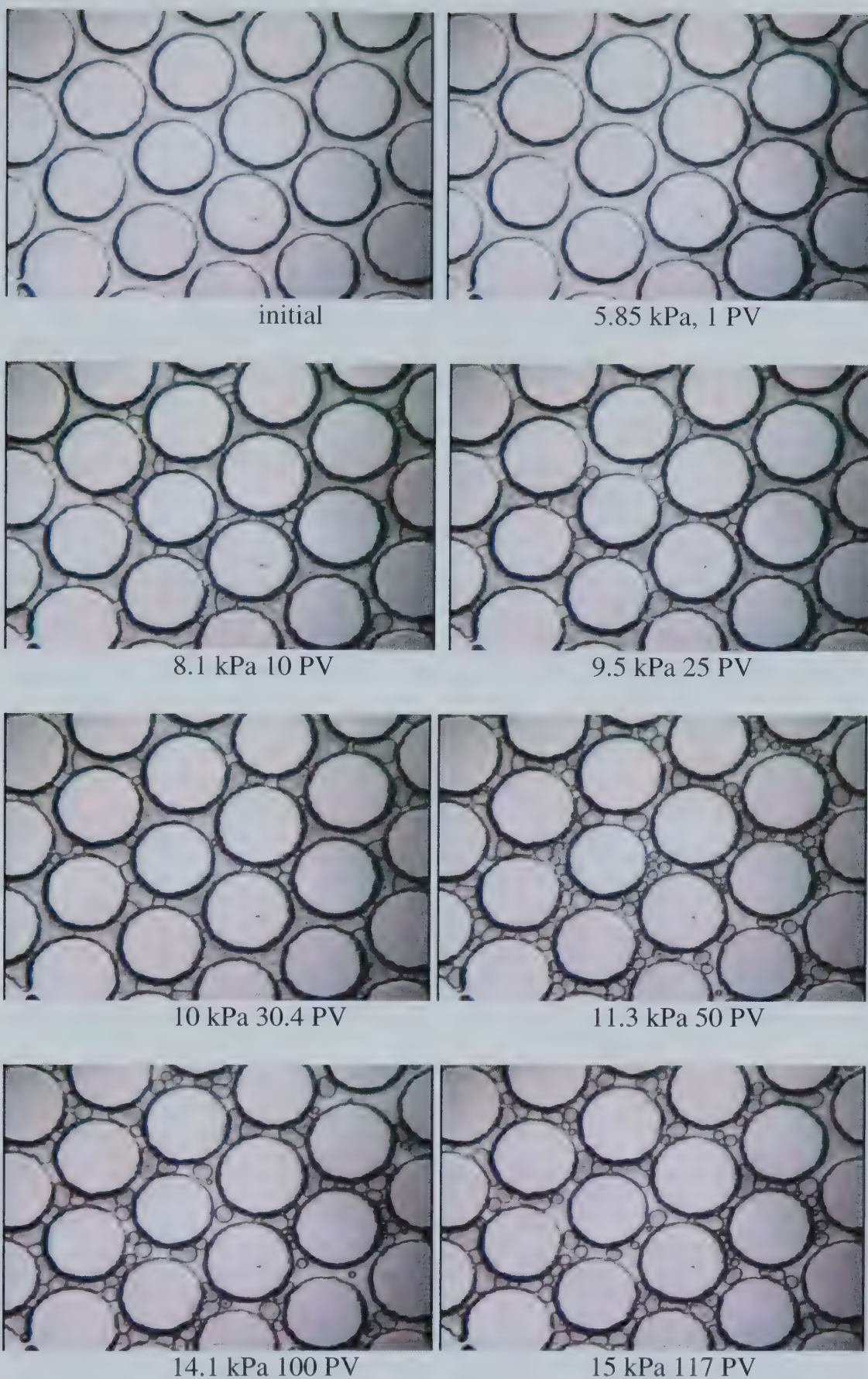
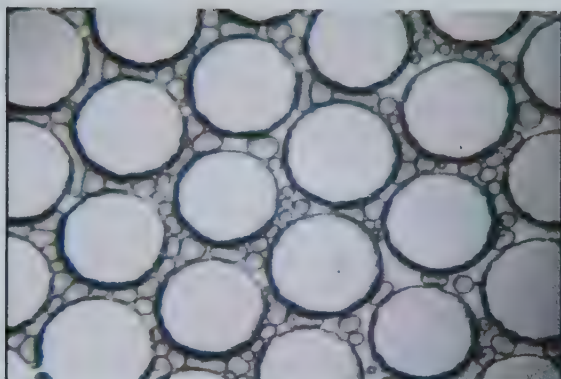
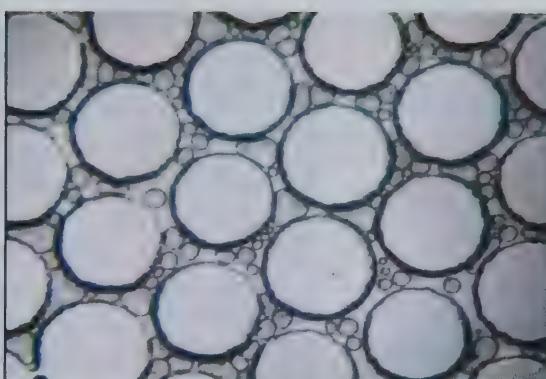


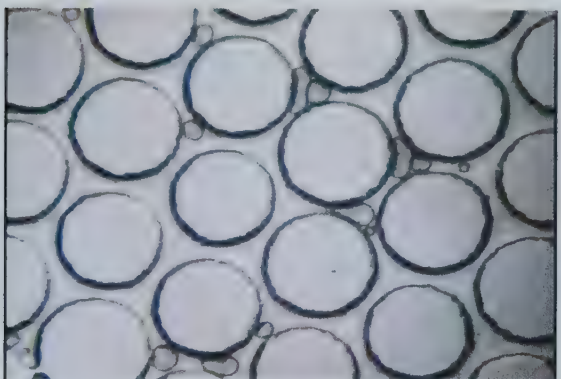
Figure C-14: Images of afoam flow through the microcell for B-P1-S2-R0.5-M1. Images taken at 1.6 x magnification.



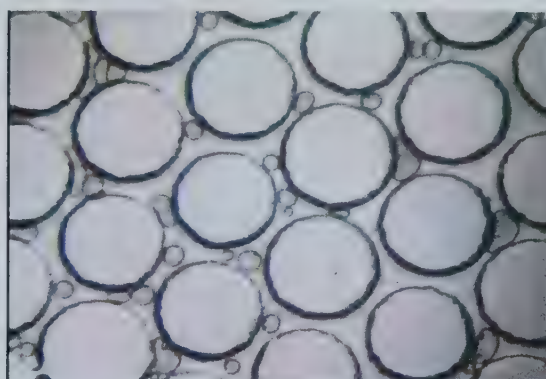
19.6 kPa 200 PV



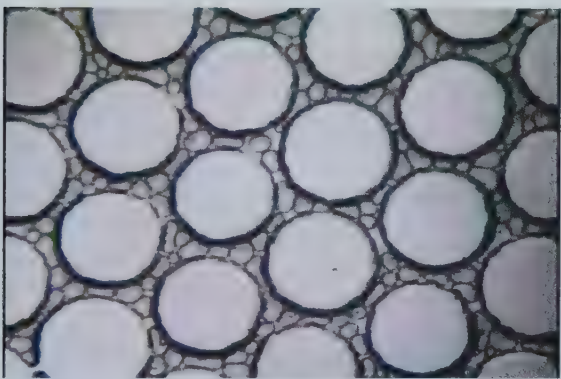
20 kPa 206.4 PV



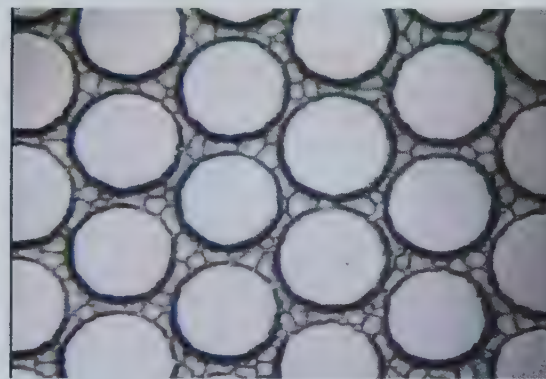
25 kPa, 300 PV



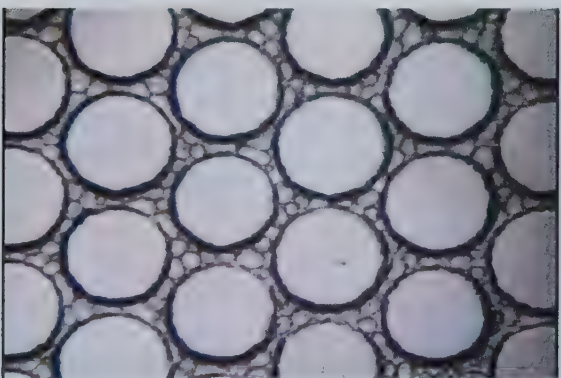
30 kPa, 381 PV



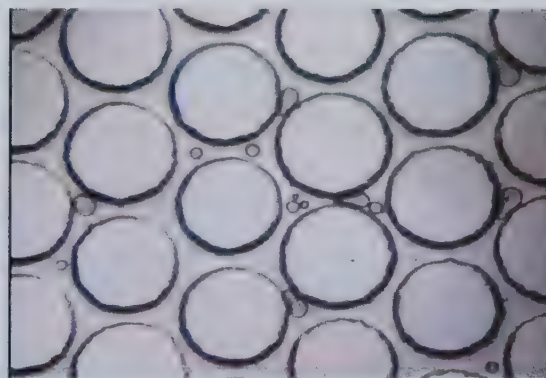
31.4 kPa, 400 PV



43.3 kPa, 578 PV

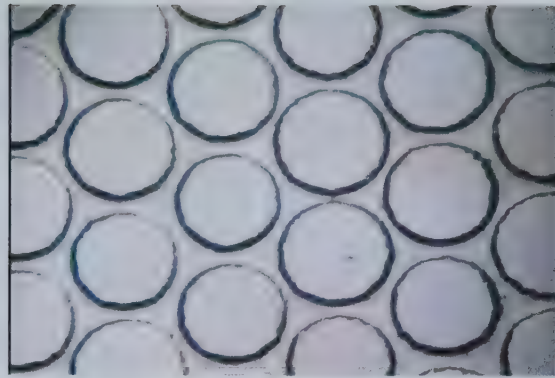


56.4 kPa, 600 PV



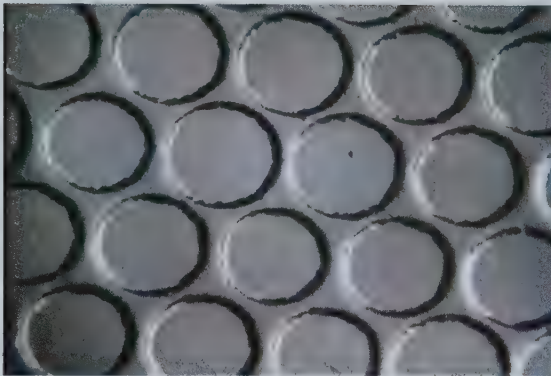
17.9 kPa, 800 PV

Figure C-14: Cont.

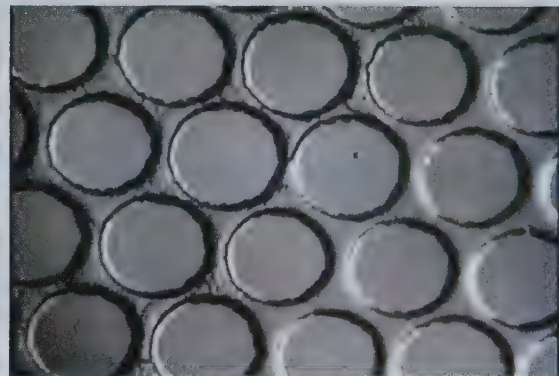


16 kPa, 1000 pv

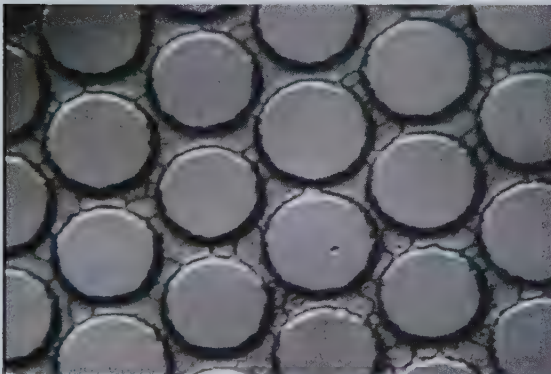
Figure C-14: Cont.



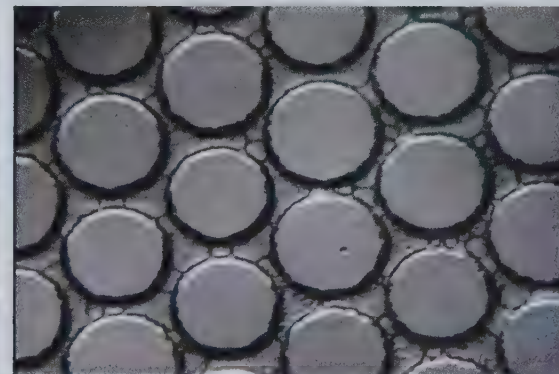
initial



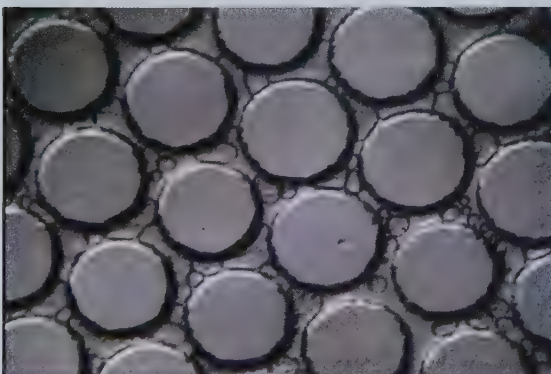
6.89 kPa 5 PV



7.6 kPa, 10 PV



8.9 kPa, 25 PV



10 kPa, 39 PV



10.9 kPa, 50 PV

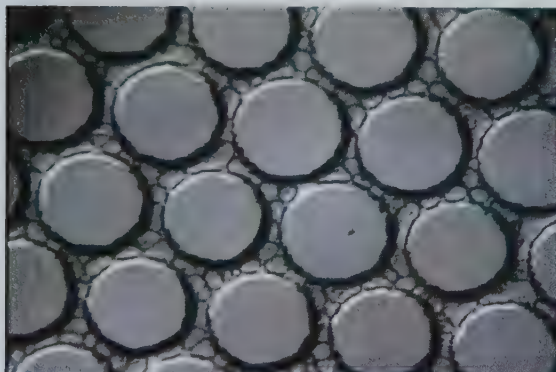
Figure C-15: Images of aphron flow through the microcell for B-P0.5-S2-R0.5-M1. Images taken at 1.6 x magnification.



15 kPa, 100 PV



20 kPa, 158 PV



23.8 kPa, 200 PV



25 kPa, 216 PV



30 kPa 271 PV



38 kPa, 375 PV



36.2 kPa, 400 PV



18 kPa, 574 PV

Figure C-15: Cont.

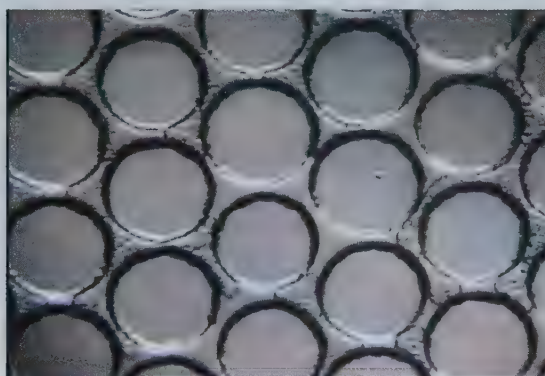


19.5 kPa, 600 PV

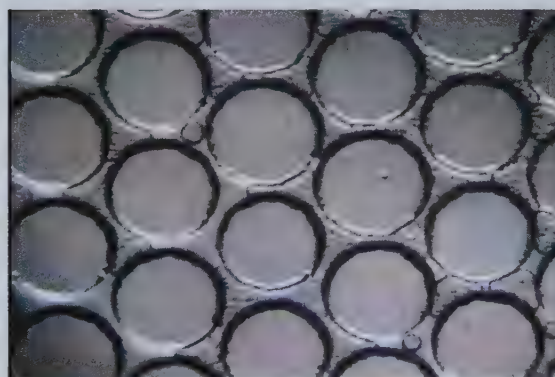
Figure C-15: Cont.



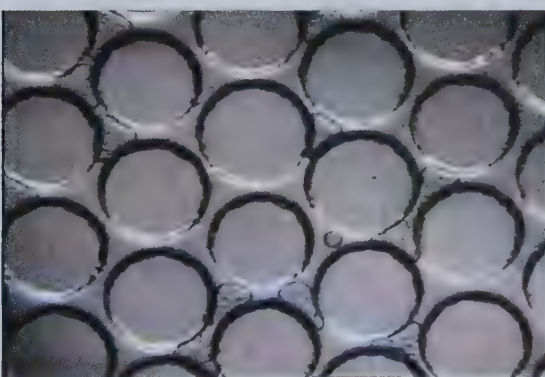
initial



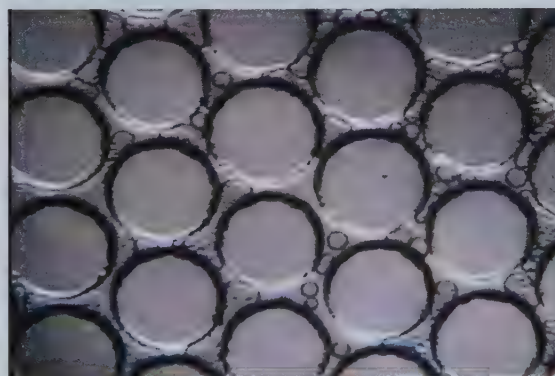
6.06 kPa 0.5 PV



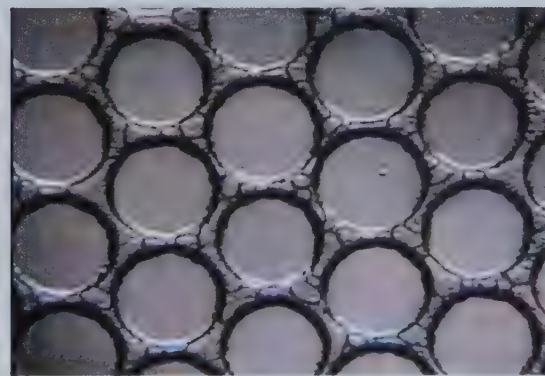
8 kPa, 10 PV



10 kPa, 25 PV

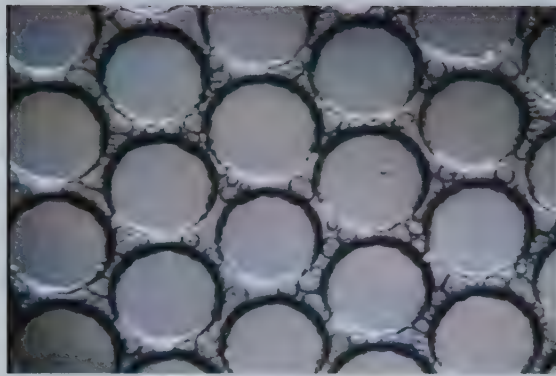


13.7 kPa, 50 PV

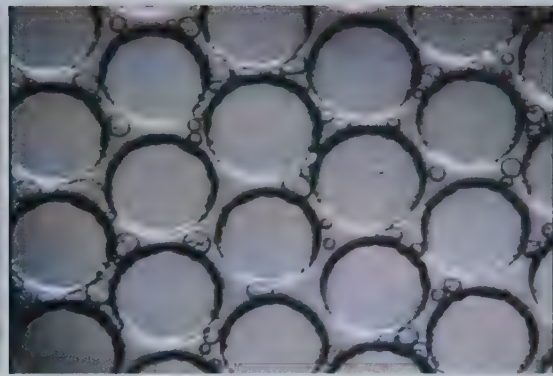


15 kPa 62 PV

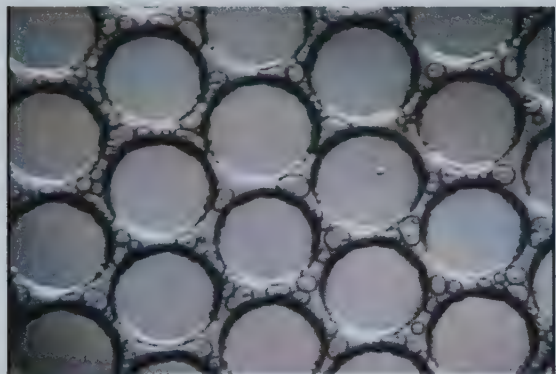
Figure C-16: Images of aphron flow through the microcell for B-P2-S2-R0.5-M1. Images taken at 1.6 x magnification.



19.3 kPa 100 PV



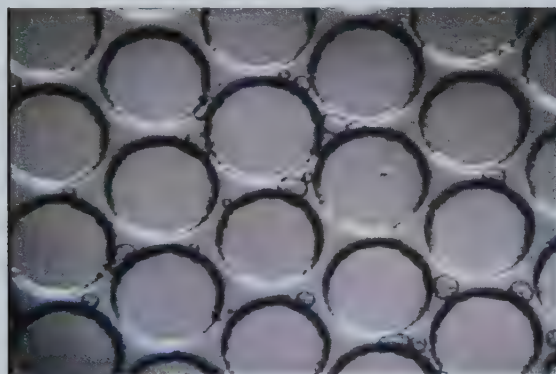
20 kPa 105 PV



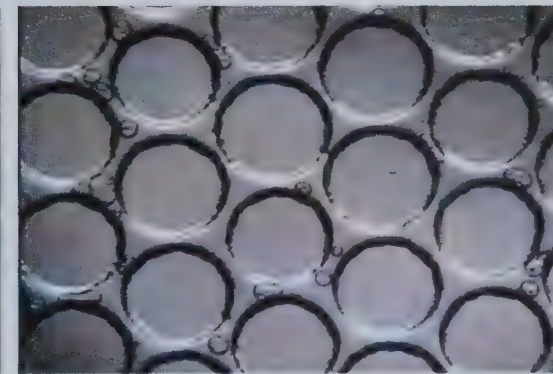
25 kPa, 147 PV



30 kPa, 184 PV



32.1 kPa, 200 PV



65.8 kPa, 400 PV



99.62 kPa 564 PV



150.3 kPa, 600 PV

Figure C-16: Cont.



32 kPa 800 PV

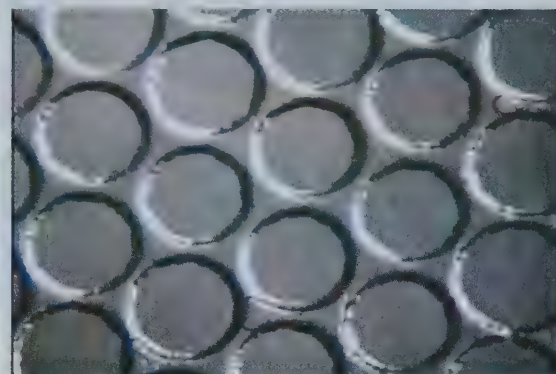


21.9 kPa 838 PV

Figure C-16: Cont.



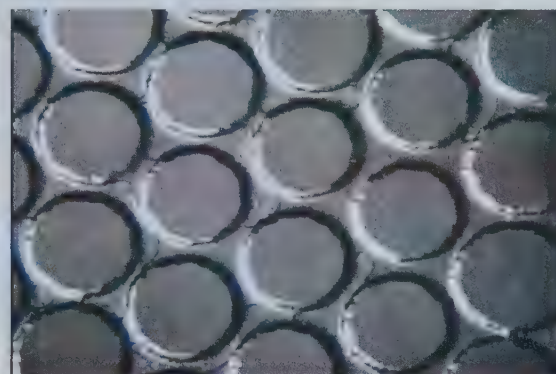
Initial



19 kPa 1 PV



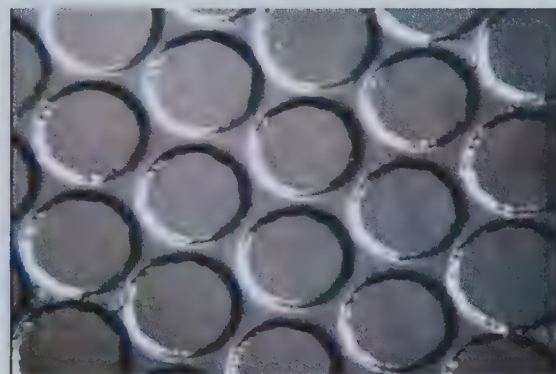
20 kPa, 10 PV



21.3 kPa 25 PV



25 kPa, 50 PV

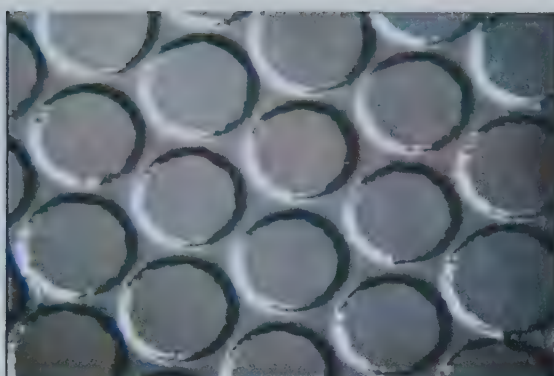


30 kPa 88 PV

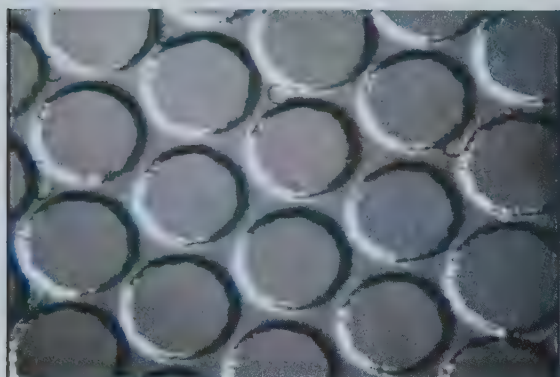
Figure C-17: Images of aphron flow through the microcell for B-P2-S0.035-R0.5-M1. Images taken at 1.6 x magnification.



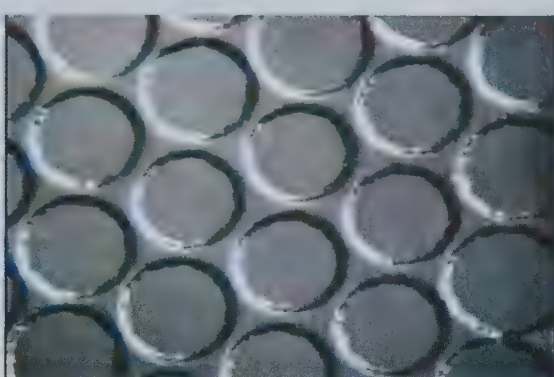
31.8 kPa, 100 PV



46.8 kPa 200 PV



57 kPa, 253 PV



100 kPa 400 PV



100 kPa 409 PV

Figure C-17:Cont.

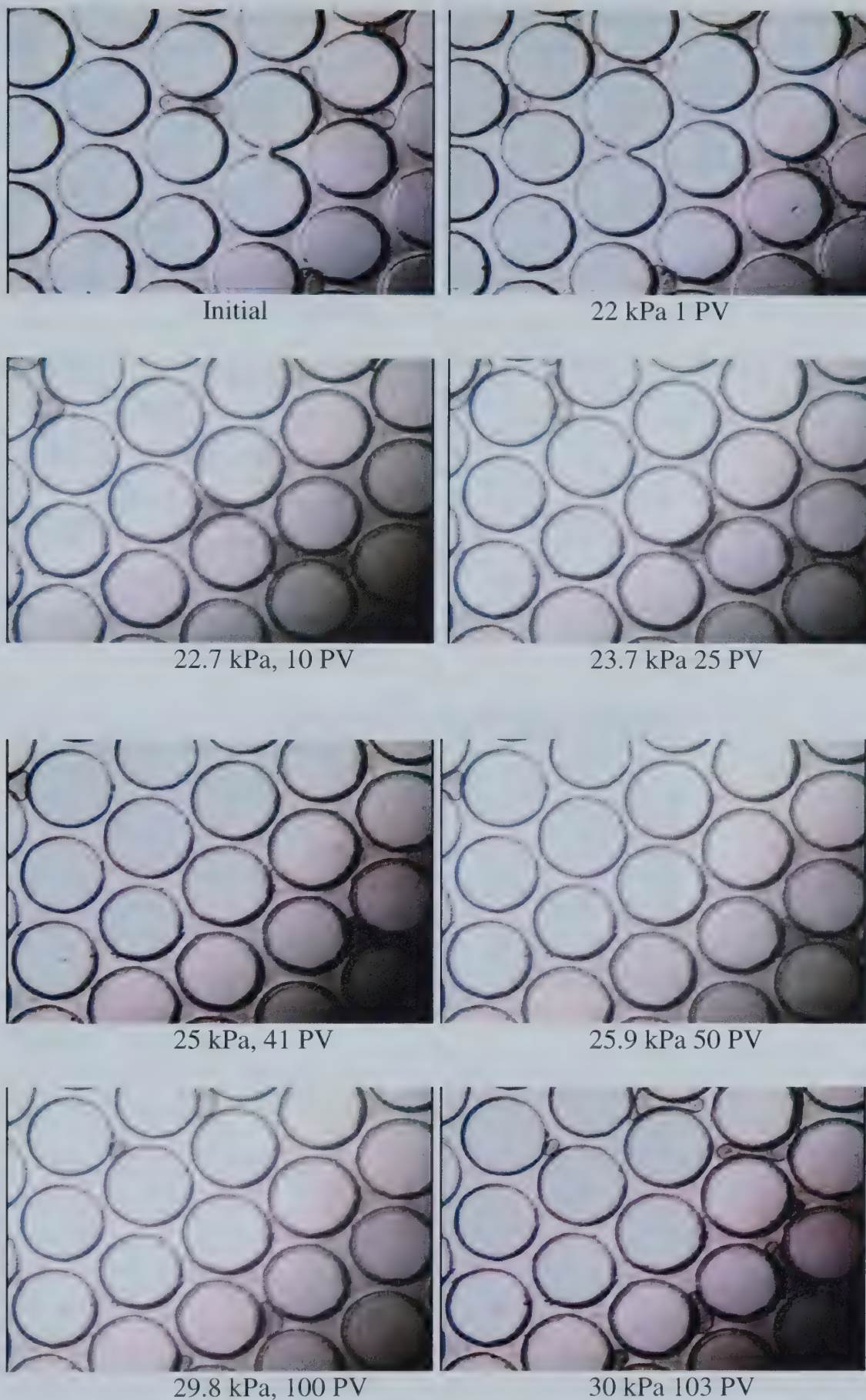
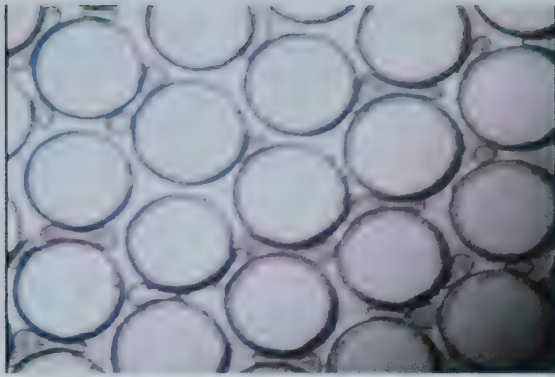
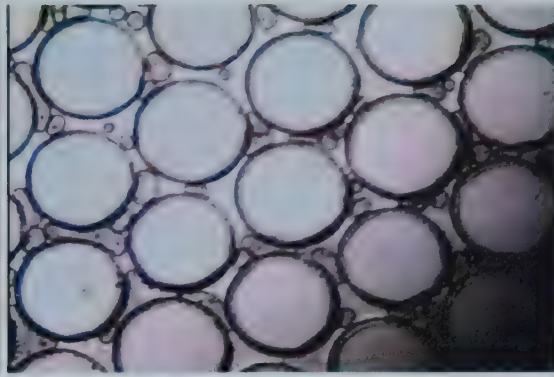


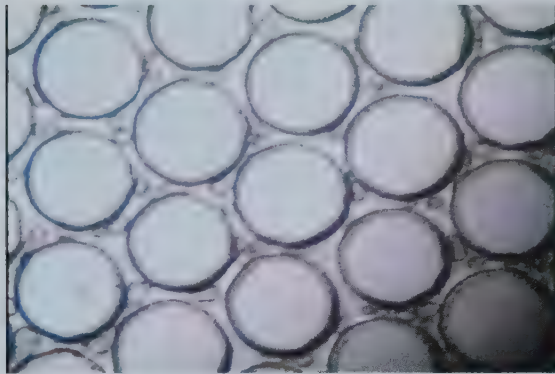
Figure C-18: Images of aphron flow through the microcell for B-P2-S1-R0.5-M1. Images taken at 1.6 x magnification.



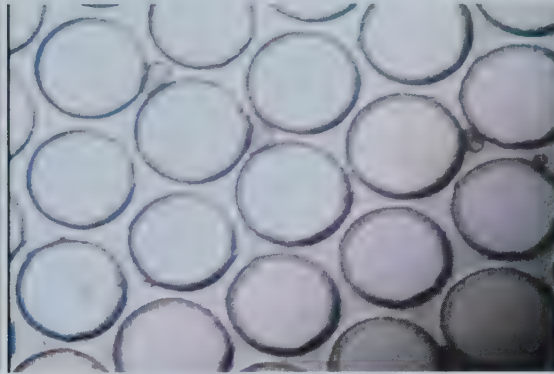
39.4 kPa, 200 PV



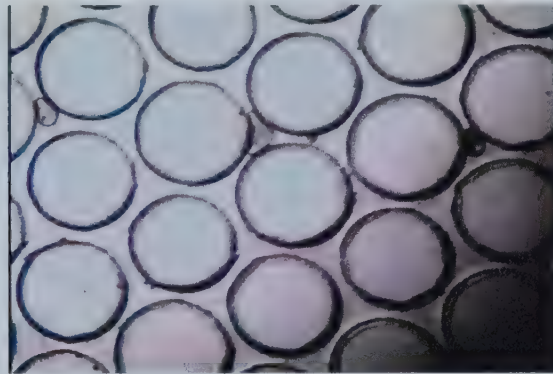
59 kPa, 368 PV



147.6 kPa, 400 PV

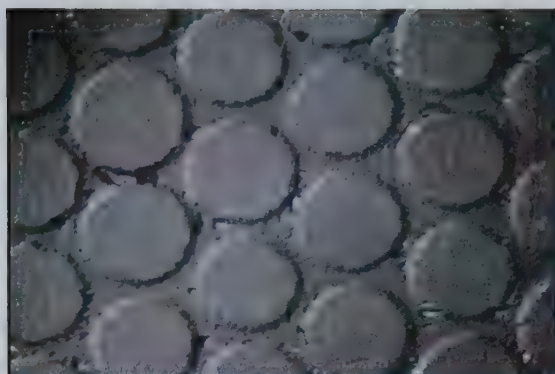


91 kPa, 600 PV



91 kPa 629 PV

Figure C-18: Cont.



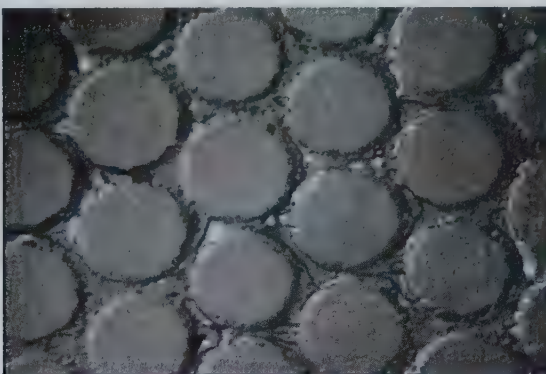
Initial



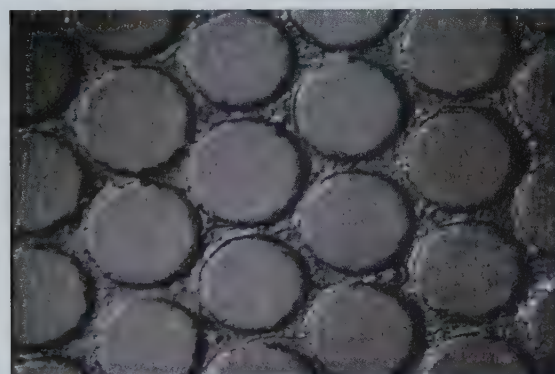
102 kPa, 1 PV



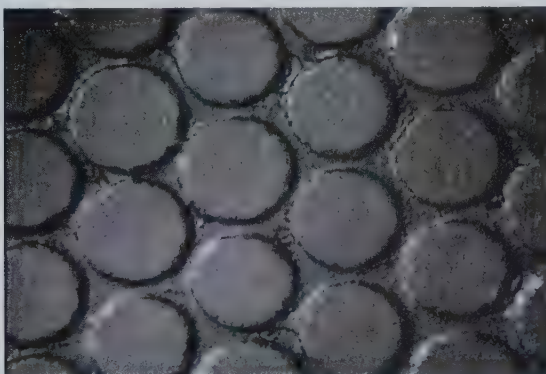
104 kPa, 10 PV



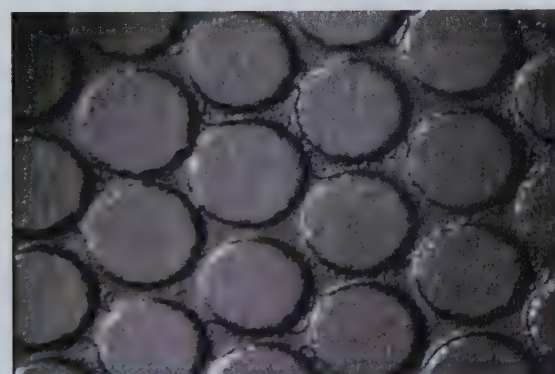
106 kPa, 25 PV



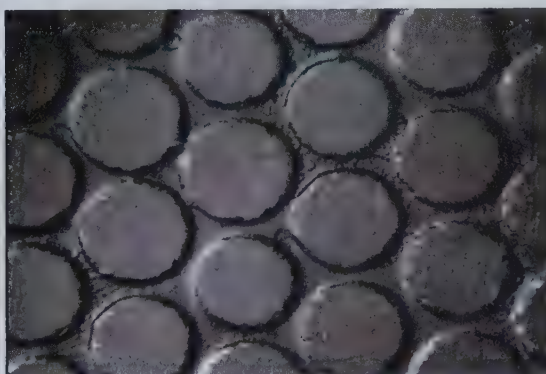
105 kPa, 50 PV



110 kPa, 61 PV

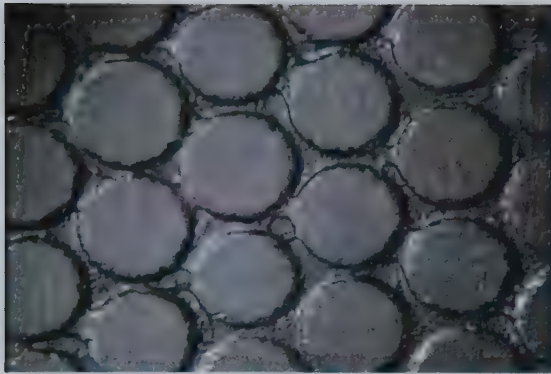


117 kPa, 100 PV

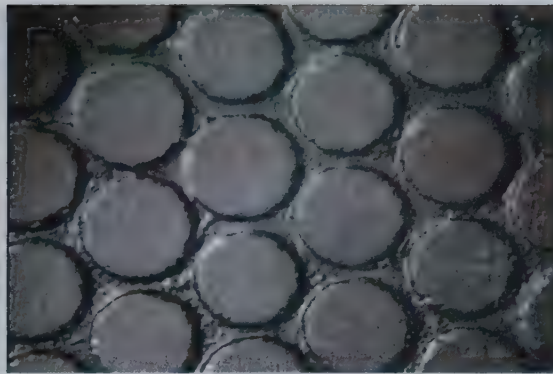


120 kPa, 118 PV

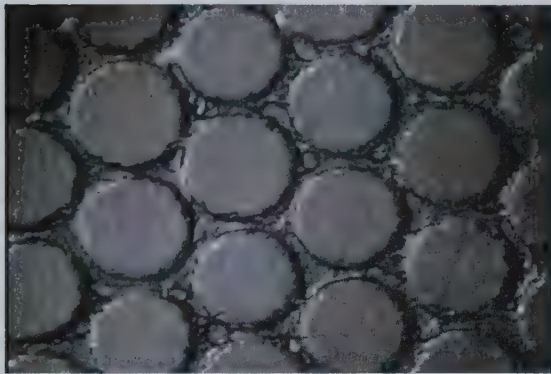
Figure C-19: Images of aphron flow through the microcell for MO-P1-S2-R1-M1. Images taken at 1.6 x magnification.



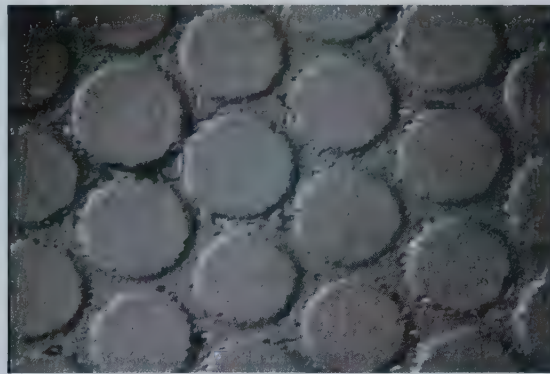
130 kPa, 168 PV



134 kPa, 200 PV



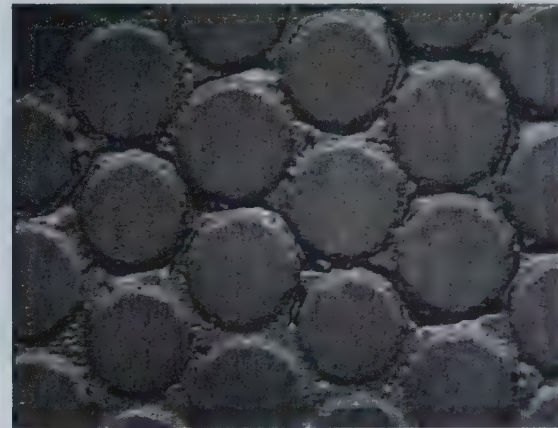
290 kPa, 235 PV



after test and depressurization



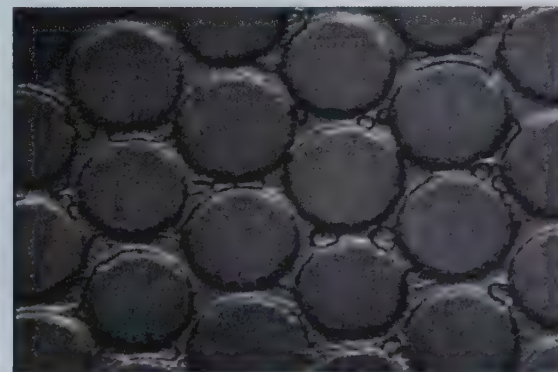
Initial



76 kPa, 1 PV



75 kPa, 10 PV

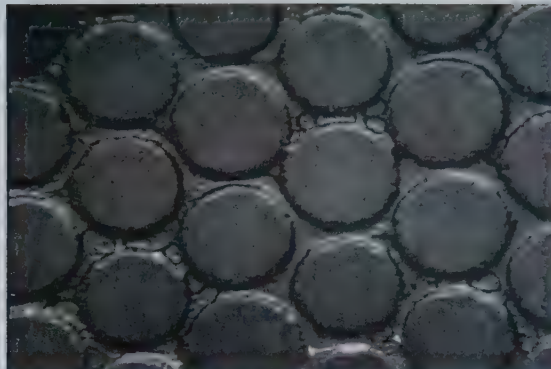


76 kPa, 25 PV

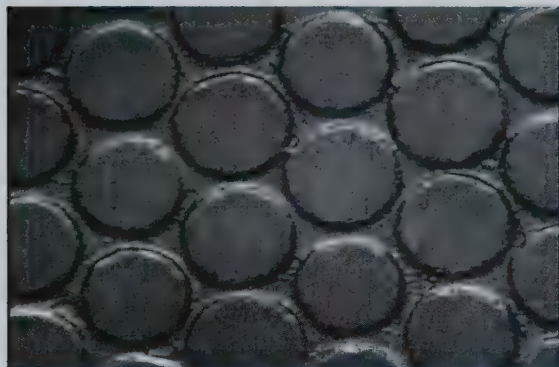
Figure C-19: Cont.



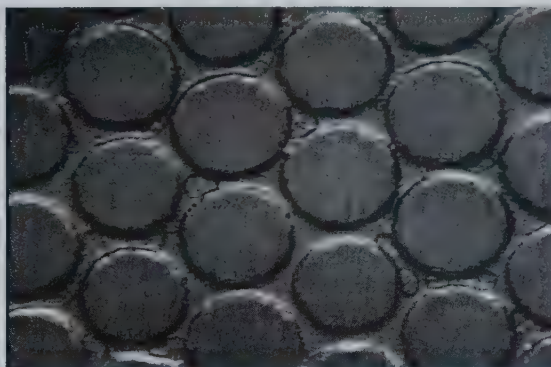
80 kPa, 40 PV



80 kPa, 50 PV



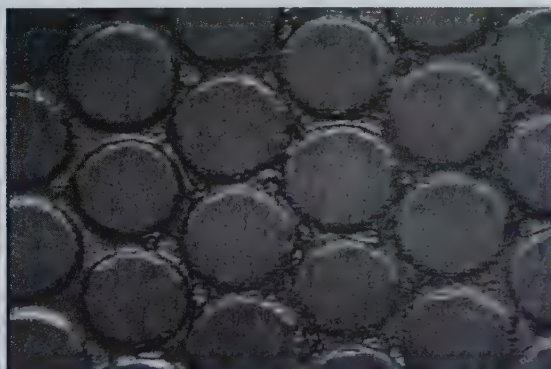
83 kPa, 100 PV



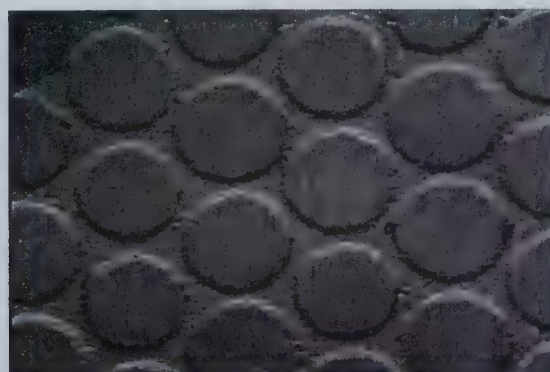
90 kPa, 156 PV



97 kPa, 200 PV

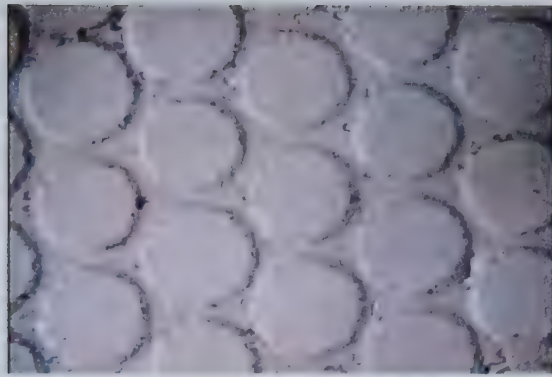


139 kPa, 242 PV

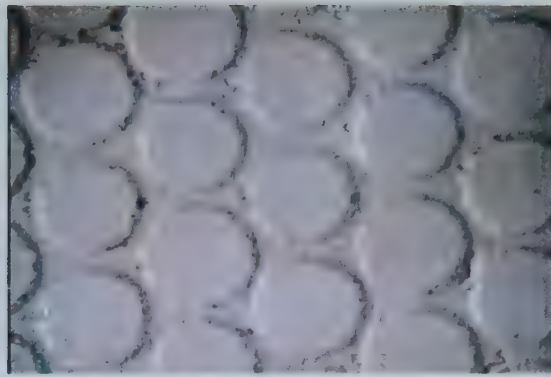


198 kPa, 251 PV

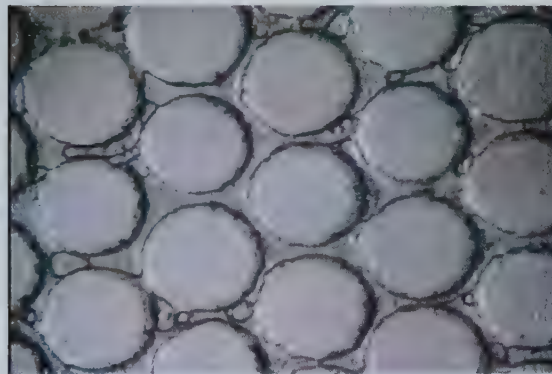
Figure C-20: Images of aphron flow through the microcell for MO-P1-S2-R0.5-M1. Images taken at 1.6 x magnification.



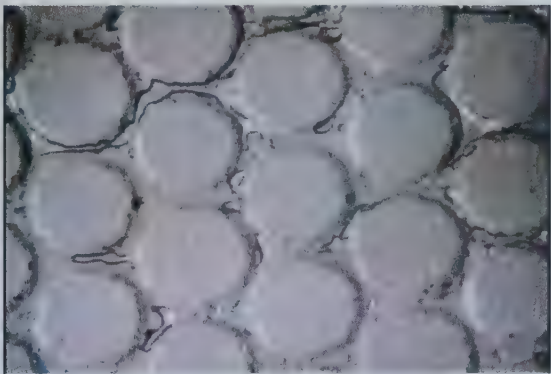
Initial



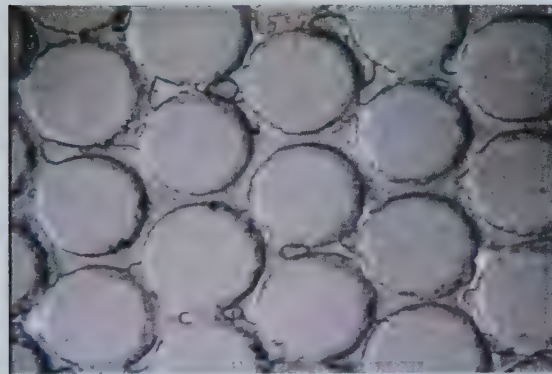
63 kPa 1PV



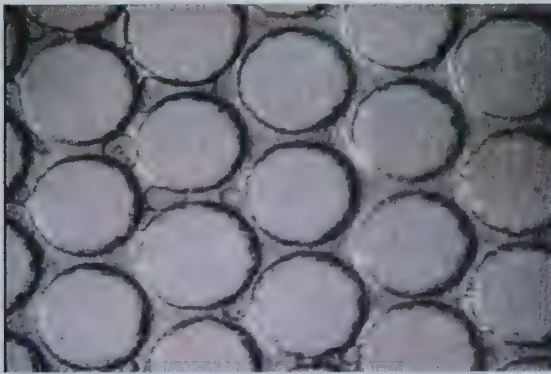
63 kPa 10 PV



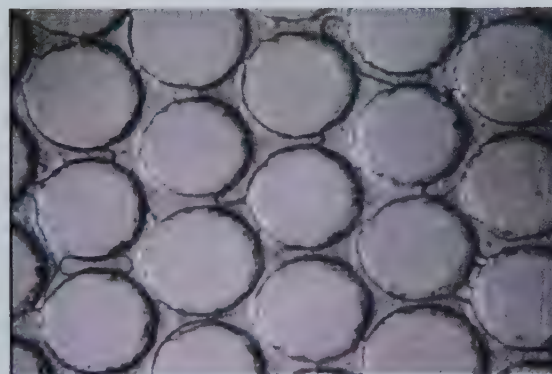
65 kPa 20 PV



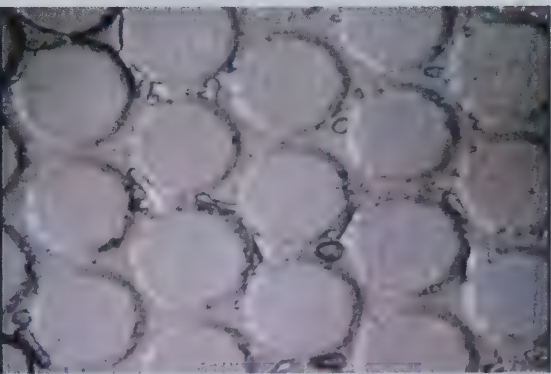
65 kPa 25 PV



65 kPa, 50 PV

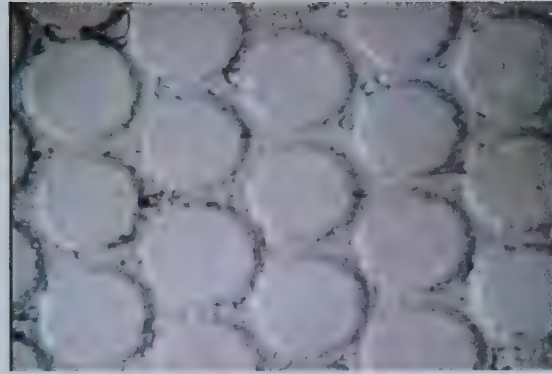


44 kPa, 98 PV



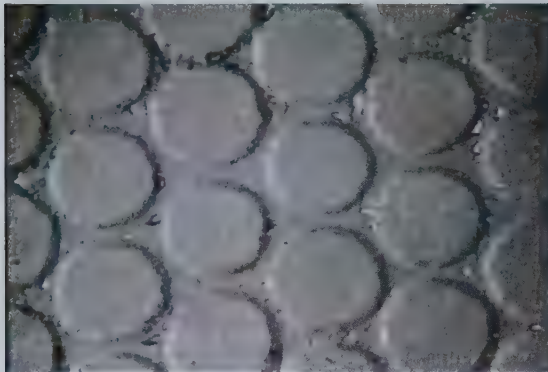
55 kPa, 100 PV

Figure C-21: Images of aphron flow through the microcell for MO-P0.5-S2-R0.5-M1. Images taken at 1.6 x magnification.

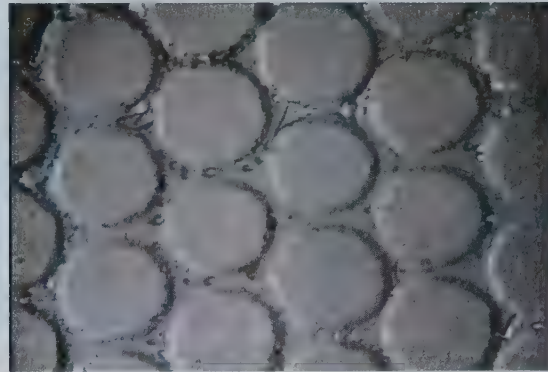


111 kPa 110 PV

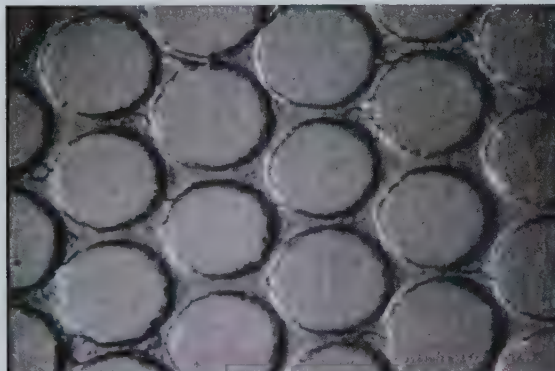
Figure C-21: Cont.



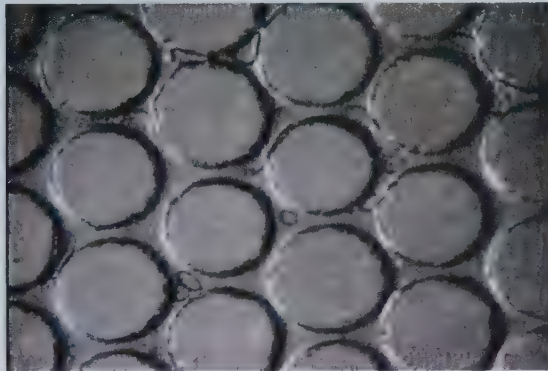
Initial



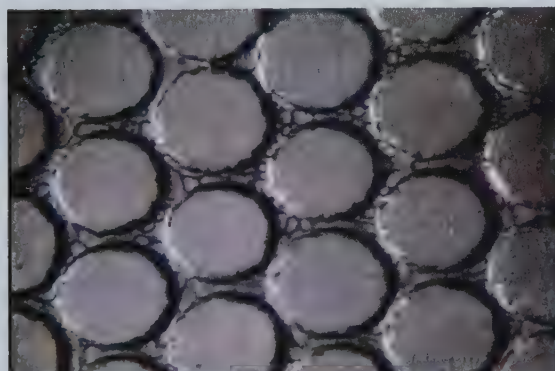
134 kPa, 1 PV



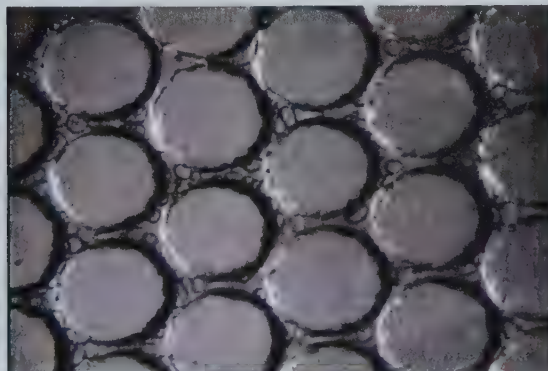
133 kPa, 10 PV



134 kPa, 25 PV

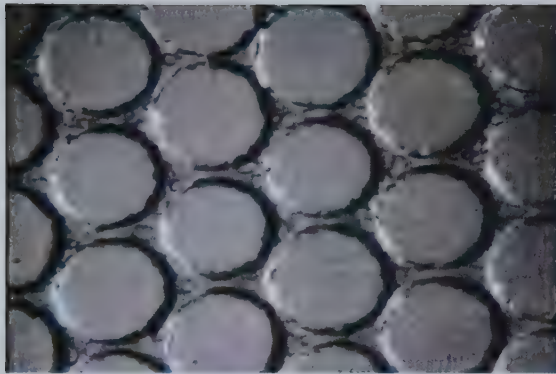


139 kPa, 50 PV

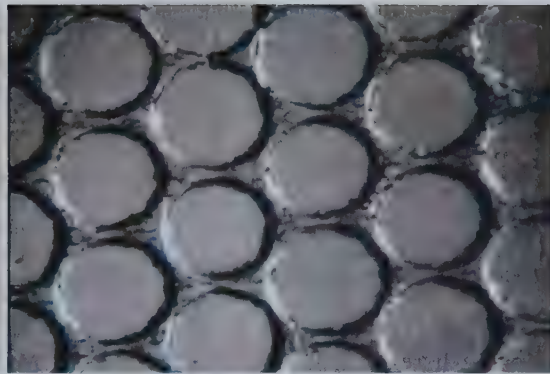


140 kPa, 54 PV

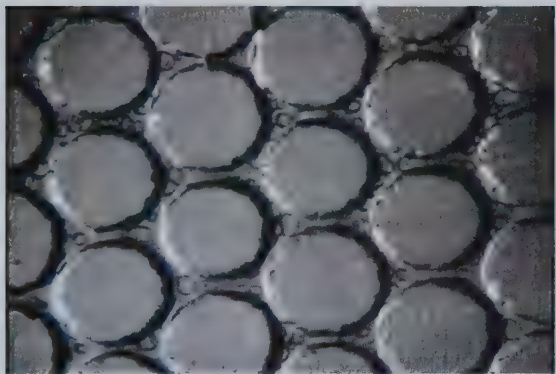
Figure C-22: Images of aphron flow through the microcell for MO-P2-S2-R0.5-M1. Images taken at 1.6 x magnification.



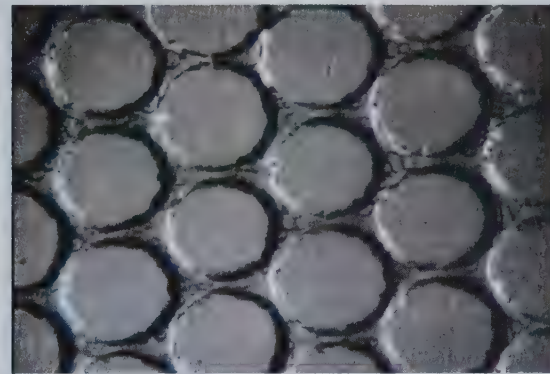
149 kPa, 100 PV



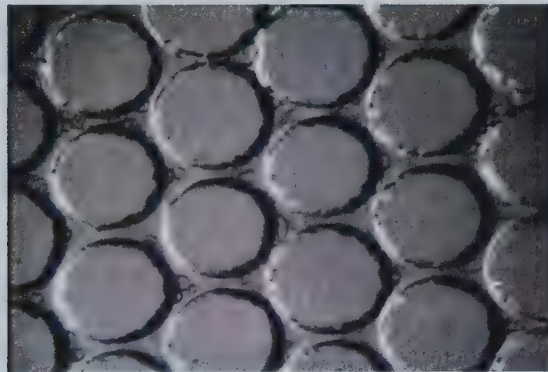
150 kPa, 103 PV



160 kPa, 142 PV



179 kPa, 148 PV



201 kPa, 153 PV

Figure C-22 Cont.

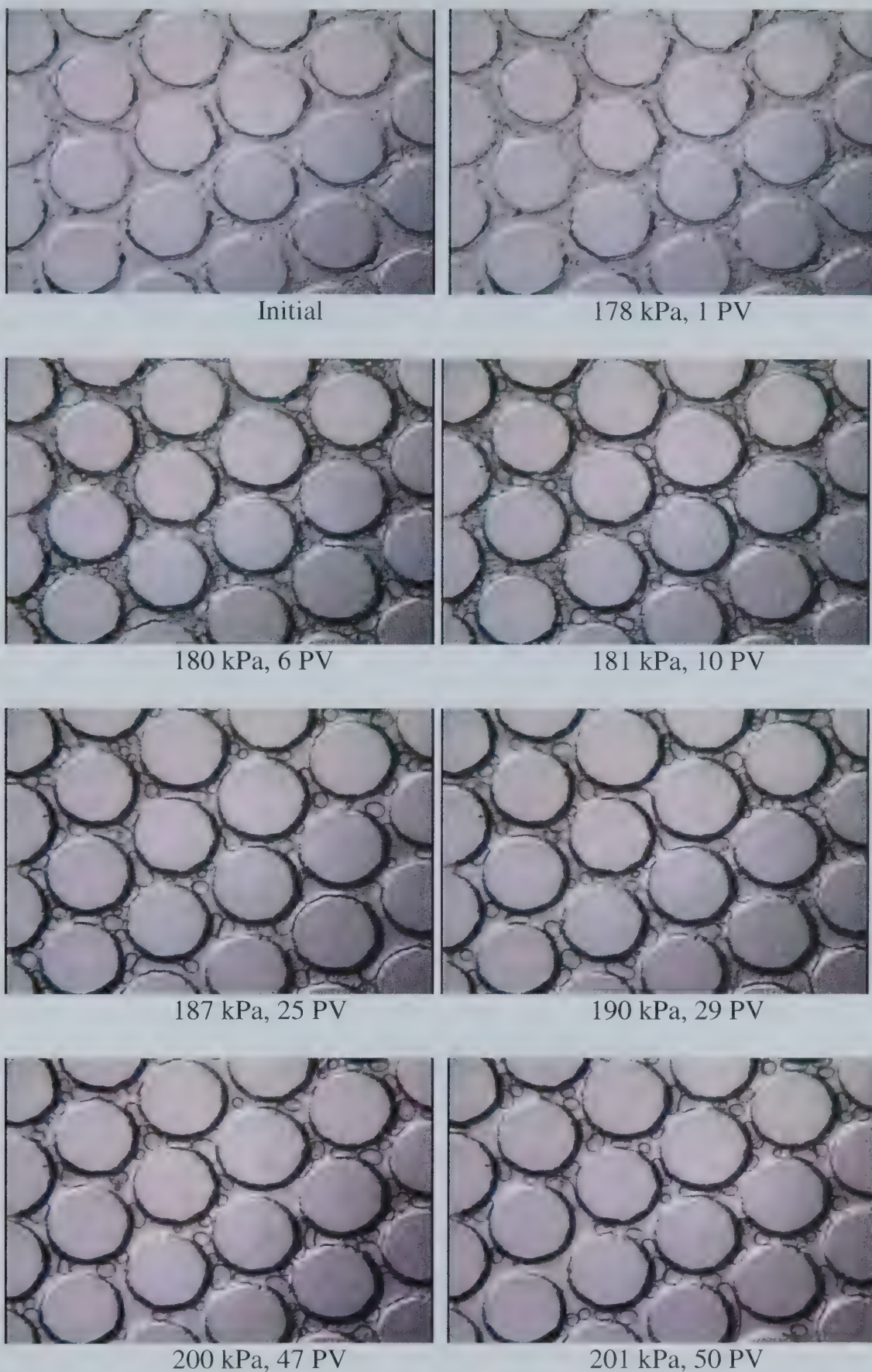


Figure C-23: Images of afoam flow through the microcell for MO-P2-S1-R0.5-M1. Images taken at 1.6 x magnification.

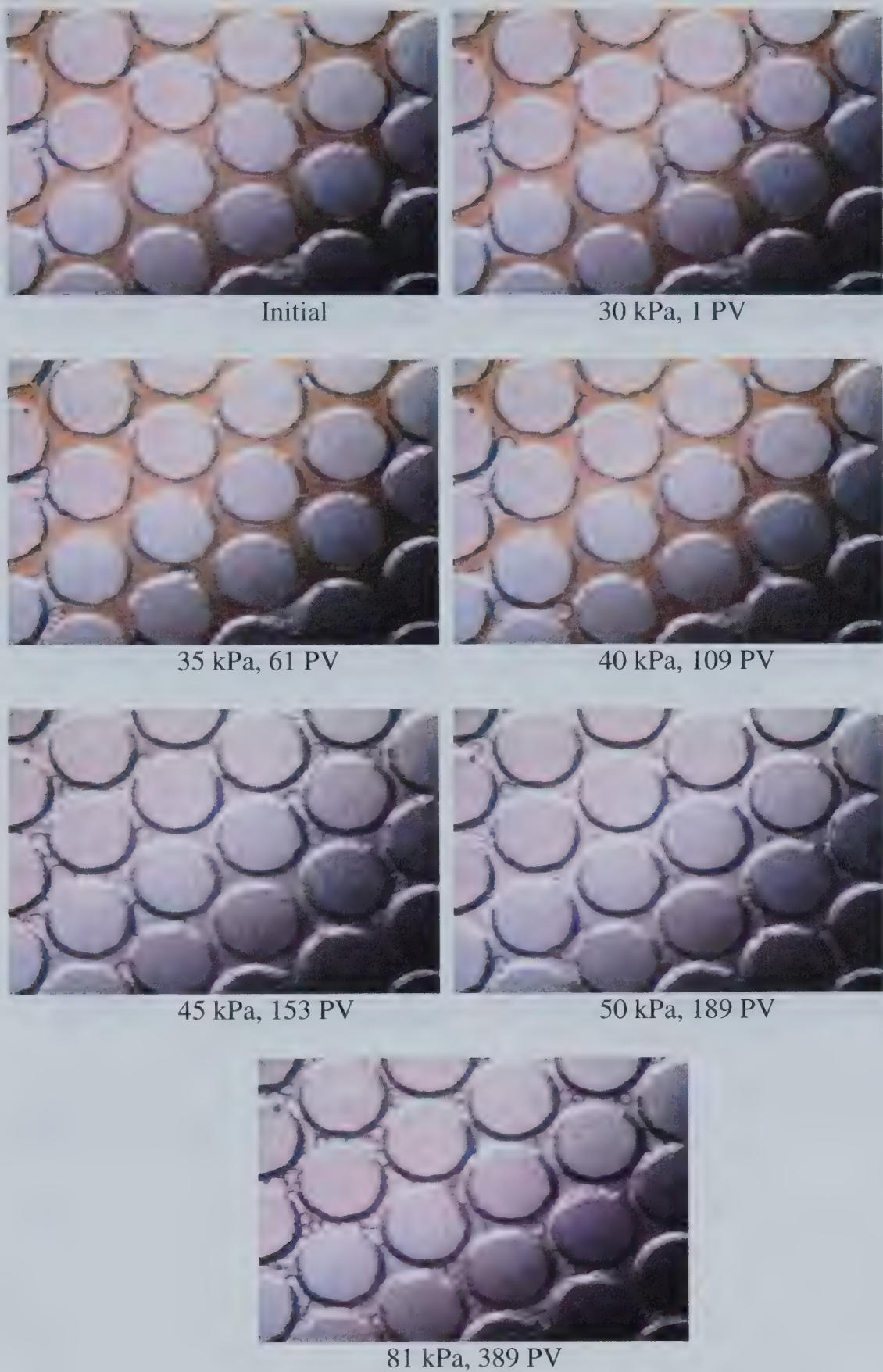
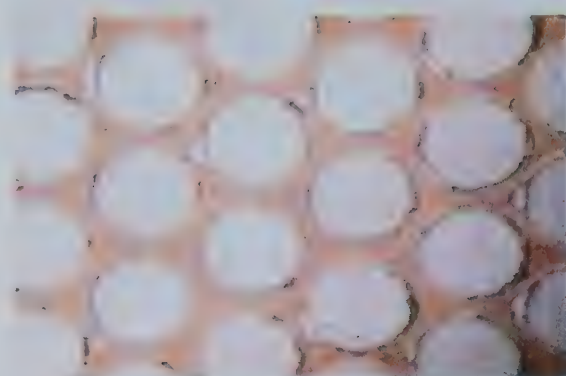
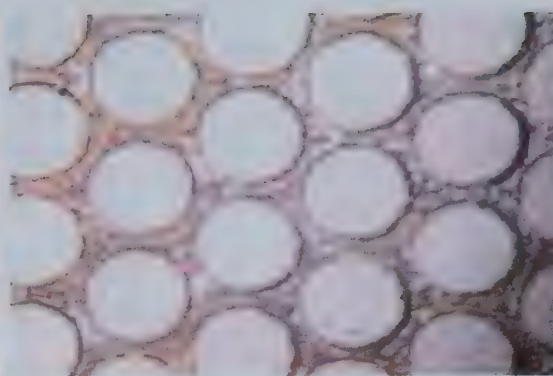


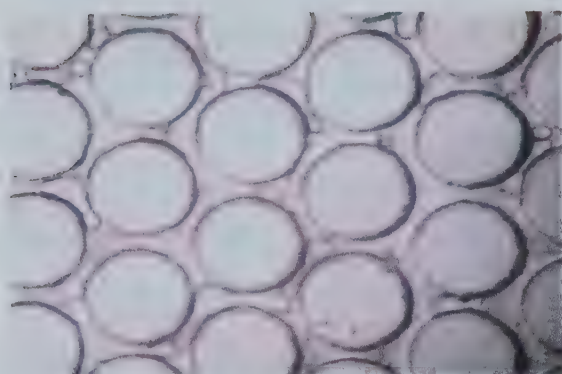
Figure C-24: Images of afoam flow through the microcell for CO-P1-S2-R1-M1. Images taken at 1.6 x magnification.



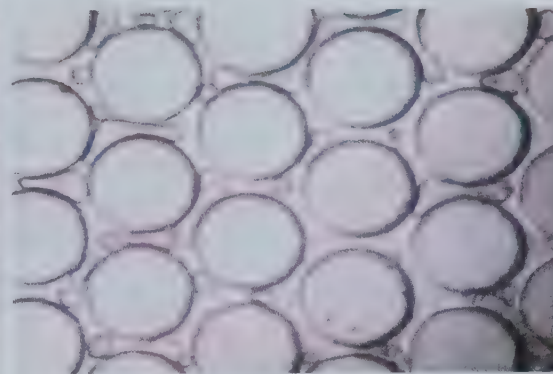
Initial



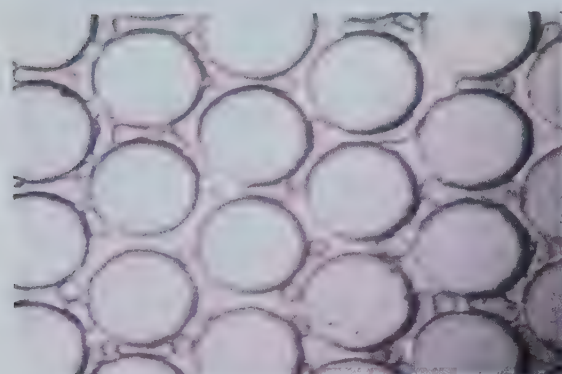
38 kPa, 1 PV



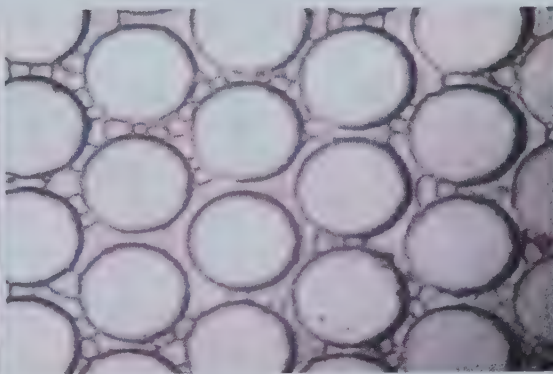
40 kPa, 22 PV



45 kPa, 80 PV



50 kPa, 134 PV



79 kPa, 382 PV

Figure C-25: Images of aphron flow through the microcell for CO-P1-S2-R0.5-M1. Images taken at 1.6 x magnification.

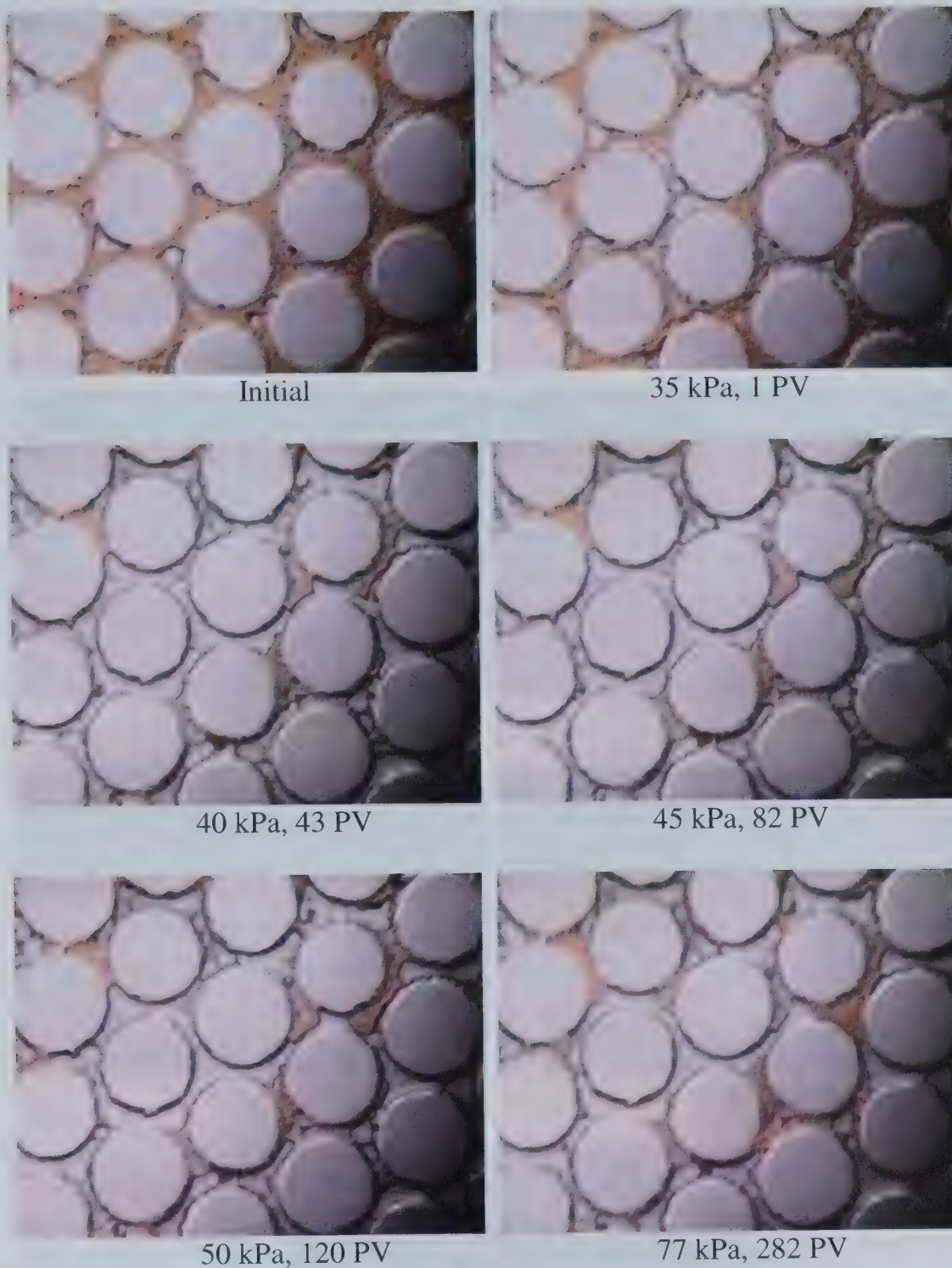


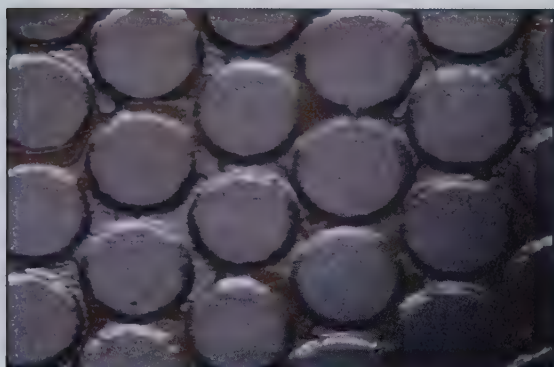
Figure C-26: Images of aphron flow through the microcell for CO-P0.5-S2-R0.5-M1. Images taken at 1.6 x magnification.



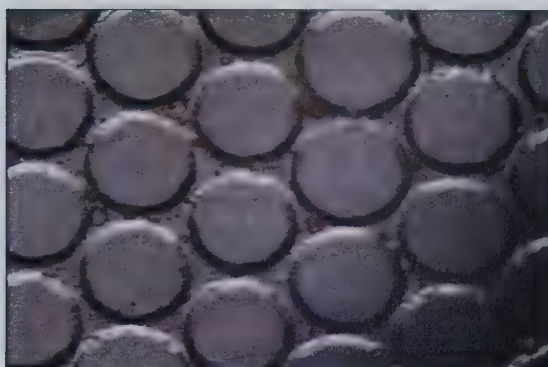
Initial



30 kPa, 1 PV



35 kPa, 30 PV



40 kPa, 79 PV



45 kPa, 124 PV



50 kPa, 164 PV



93 kPa, 413 PV

Figure C-27: Images of aphron flow through the microcell for CO-P2-S2-R0.5-M1. Images taken at 1.6 x magnification.



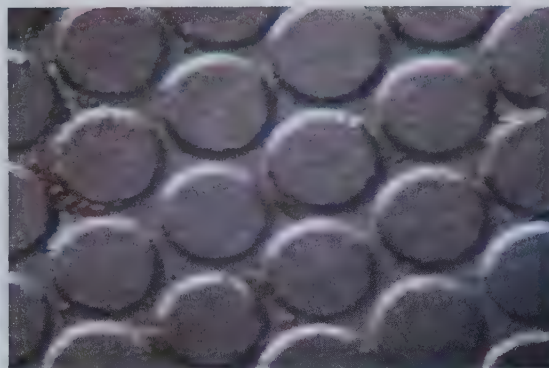
Initial



24 kPa, 1 PV



25.6 kPa, 10 PV



28.4 kPa, 25 PV



30 kPa, 34 PV



32.7 kPa, 50 PV



35 kPa, 63 PV



40 kPa, 90 PV

Figure C-28: Images of aphron flow through the microcell for CO-P2-S0.035-R0.5-M1. Images taken at 1.6 x magnification.



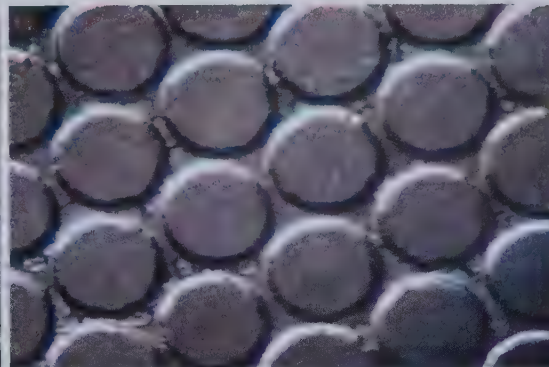
42.1 kPa, 100 PV



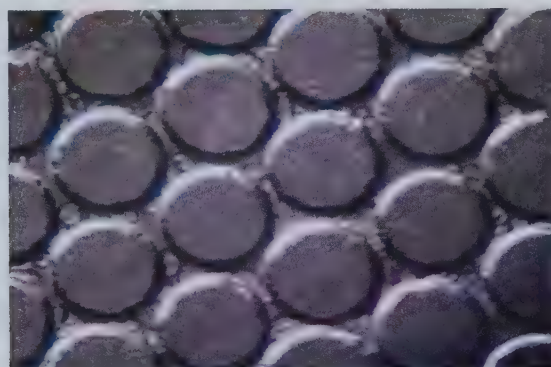
45 kPa, 114 PV



50 kPa, 135 PV



69 kPa, 200 PV



99 kPa, 279 PV

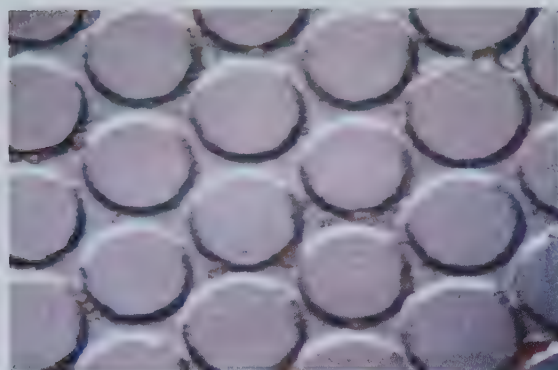
Figure C-28: Cont.



Initial



24 kPa, 1 PV



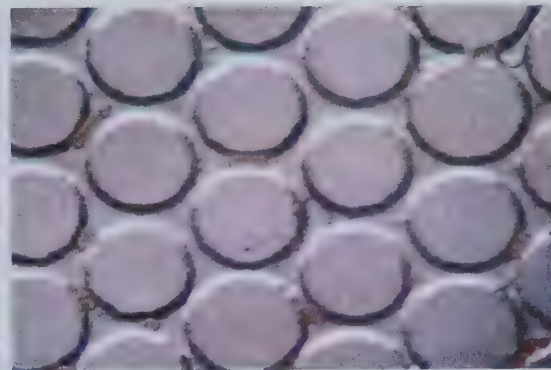
25.2 kPa, 10 PV



27.4 kPa, 25 PV



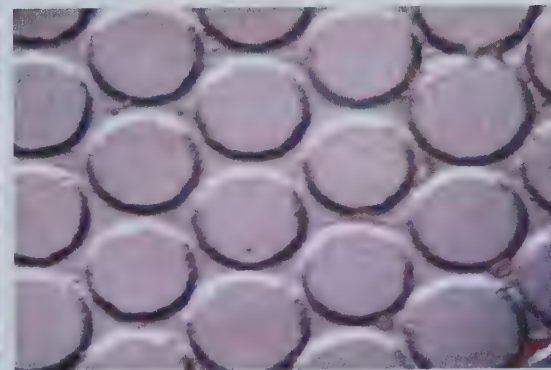
30 kPa, 44 PV



30.7 kPa, 50 PV



35 kPa, 83 PV

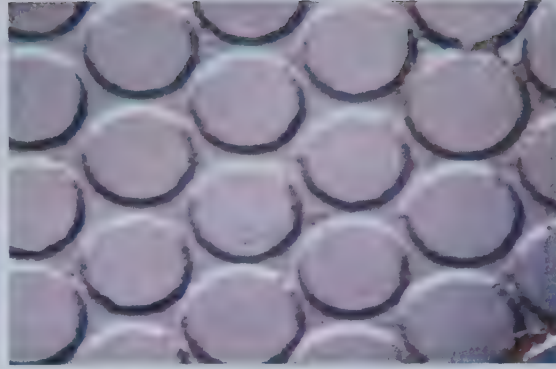


37.3 kPa, 100 PV

Figure C-29: Images of aphron flow through the microcell for CO-P2-S1-R0.5-M1. Images taken at 1.6 x magnification.



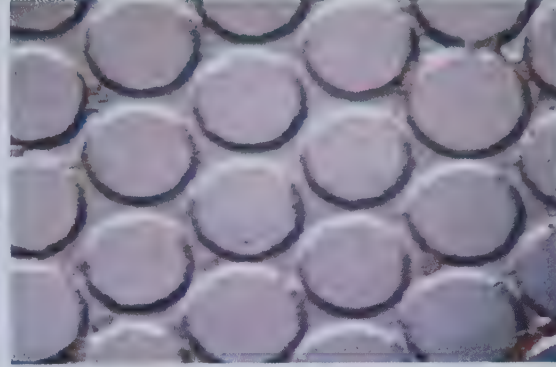
40 kPa, 119 PV



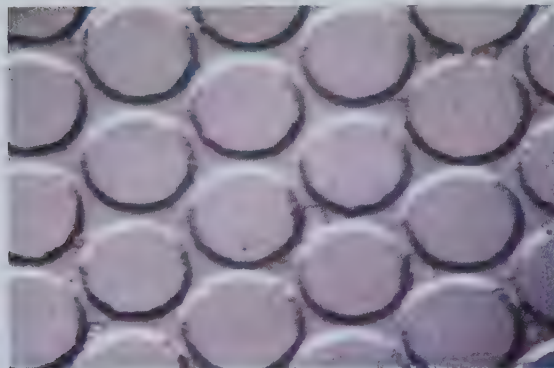
45 kPa, 151 PV



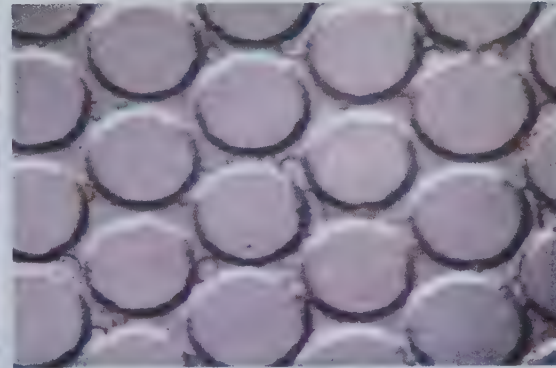
50 kPa, 180 PV



53.5 kPa, 200 PV



106 kPa, 400 PV



123 kPa, 444 PV

Figure C-29: Cont

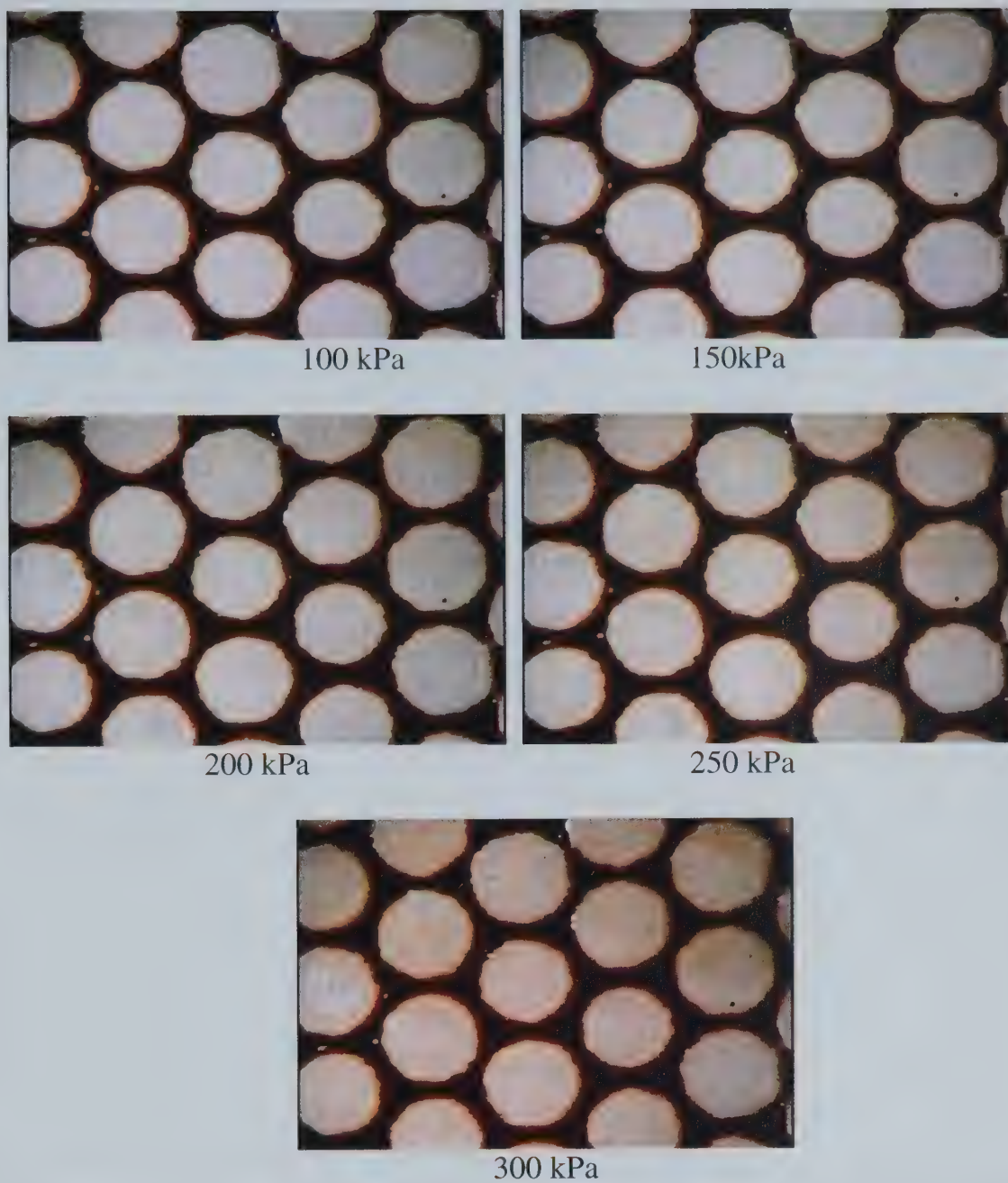


Figure C-30: Images of aphron flow through the microcell for 11,000 cP cude oil. Images taken at 1.6 x magnification.

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